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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the fiscal year ended December 31, 2003.

or

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the transition period from ----------------------------- to ----------------------------- .

Commission file number 000-30586

IVANHOE ENERGY INC.

(Exact name of registrant as specified in its charter)

Yukon, Canada
(State or other jurisdiction of incorporation or organization)

98- 0372413
(I.R.S. Employer Identification No.)

654 — 999 Canada Place
Vancouver, British Columbia, Canada
V6C 3E1
(Address of principal executive offices)

(604) 688-8323
(Registrant's telephone number, including area code)

Securities to be registered pursuant to Section 12(b) of the Act: None

Securities registered or to be registered pursuant to Section 12(g) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares, no par value	The Toronto Stock Exchange NASDAQ SmallCap Market

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is an accelerated filer as defined in Rule 12b-2 of the Act.

Yes [X] No [ ]

As of March 1, 2004, 161,567,497 common shares of the Registrant were issued and outstanding. The aggregate market value of the voting stock held by non-affiliates of the Registrant on June 30, 2003 based on the closing price on the NASDAQ SmallCap on that date, was $159,495,080.

Documents incorporated by reference: None

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CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to "dollars" or to "$" are to U.S. dollars and all references to "Cdn.$" are to Canadian dollars. The closing, low, high and average noon buying rates in New York for cable transfers for the conversion of Canadian dollars into U.S. dollars for each of the five years ended December 31 as reported by the Federal Reserve Bank of New York were as follows:

	2003	2002	2001	2000	1999
Closing.............	$ 0.77	$ 0.63	$ 0.63	$ 0.67	$ 0.69
Low..................	$ 0.63	$ 0.62	$ 0.62	$ 0.64	$ 0.64
High..................	$ 0.77	$ 0.66	$ 0.67	$ 0.70	$ 0.69
Average Noon...	$ 0.71	$ 0.63	$ 0.65	$ 0.67	$ 0.67

The average noon rate of exchange reported by the Federal Reserve Bank of New York for conversion of U.S. dollars into Canadian dollars on March 1, 2004 was $ 0.75 ($1.00 = Cdn.$1.34). Exchange rates are based upon the noon buying rate in New York City for cable transfers in foreign currencies as certified for customs purposes by the Federal Reserve Bank of New York.

ABBREVIATIONS

As generally used in the oil and gas business and in this Annual Report, the following terms have the following meanings:

Boe	= barrel of oil equivalent
Bbl	= barrel
MBbl	= thousand barrels
MMBbl	= million barrels
Bopd	= barrels of oil per day
Bbls/d	= barrels of per day
Boe/d	= barrels of oil equivalent per day
MBbls/d	= thousand barrels per day
MMBls/d	= million barrels per day
MMBtu	= million British thermal units
Mcf	= thousand cubic feet
MMcf	= million cubic feet
Mcf/d	= thousand cubic feet per day
MMcf/d	= million cubic feet per day

When we refer to oil in "equivalents," we are doing so to compare quantities of oil with quantities of gas or to express these different commodities in a common unit. In calculating Bbl equivalents, we use a generally recognized standard in which one Bbl is equal to six Mcf. Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance or achievements, or other future events, to be materially different from any future results, performance or achievements or other events expressly or implicitly predicted by such forward-looking statements. Such risks, uncertainties and other factors include, but are not limited to, our short history of limited revenue, losses and negative cash flow from our current exploration and development operations in the U.S. and China; our limited cash resources and consequent need for additional financing; uncertainties regarding the potential success of our oil and gas exploration and development projects in the U.S. and China; uncertainties regarding the potential success of gas-to-liquids technology; oil price volatility; oil and gas industry operational hazards and environmental concerns; government regulation and requirements for permits and licenses, particularly in the foreign jurisdictions in which we carry on business; title matters; risks associated with carrying on business in foreign jurisdictions; conflicts of interests; competition for a limited number of promising oil and gas exploration properties from larger more well financed oil and gas companies; and other statements contained herein regarding matters that are not historical facts. Forward-looking statements can often be identified by the use of forward-looking terminology such as "may", "will", "expect", "intend", "estimate", "anticipate", "believe" or "continue" or the negative thereof or variations thereon or similar terminology. We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. We undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements.

ENFORCEABILITY OF CIVIL LIABILITIES

We have been organized under the laws of Canada and our executive offices are located in British Columbia, Canada. Some of our directors, controlling persons and officers and representatives of the experts named in this Annual Report on Form 10-K reside outside the U.S. and a substantial portion of their assets and our assets are located outside the U.S. As a result, it may be difficult for you to effect service of process within the U.S. upon the directors, controlling persons, officers and representatives of experts who are not residents of the U.S. or to enforce against them judgments obtained in the courts of the U.S. based upon the civil liability provisions of the federal securities laws or other laws of the U.S. There is doubt as to the enforceability in Canada against us or against any of our directors, controlling persons, officers or experts who are not residents of the U.S., in original actions or in actions for enforcement of judgments of U.S. courts, of liabilities based solely upon civil liability provisions of the U.S. federal securities laws. Therefore, it may not be possible to enforce those actions against us, our directors and officers or experts named in this Annual Report on Form 10-K.

AVAILABLE INFORMATION

Copies of our annual reports on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge on or through our website at http://www.ivanhoe-energy.com/or through the Securities and Exchange Commission's website at http://www.sec.gov/.

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

CORPORATE OVERVIEW

We are an international energy company engaged in the exploration for and production of oil and gas, enhanced oil recovery and natural gas projects and the application of heavy-to-light oil upgrading and gas-to-liquids technologies. We were incorporated pursuant to the laws of the Yukon, Canada, on February 21, 1995 under the name 888 China Holdings Limited. We were largely inactive until early 1996. On June 3, 1996, we changed our name to Black Sea Energy Ltd., and on June 24, 1999, we changed our name to Ivanhoe Energy Inc.

Our authorized capital consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

Our principal executive offices are located at Suite 654 — 999 Canada Place, Vancouver, British Columbia, V6C 3E1, and our registered and records offices are located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9.

HISTORICAL OVERVIEW

Ivanhoe Energy Inc. is a company focused on three major strategies: (1) conventional exploration and production ("E&P"), primarily oil and natural gas in the U.S and China; (2) enhanced oil recovery ("EOR") and natural gas projects, on a production-sharing basis, with national petroleum companies and other operators; and (3) monetization of stranded oil and gas reserves though the application of advanced technologies such as heavy-to-light and gas-to-liquids ("GTL") technologies.

Following our incorporation in February 1995, we were largely inactive until early 1996. Initially, our strategy was to seek out existing oil and gas properties in Russia on which past field development practices did not maximize reserve recoveries and to establish joint ventures with local partners to enhance oil recovery. However, after successfully increasing oil production and reserves at the Kalchinskoye field in western Siberia, a dispute with our partner prevented us from proceeding with operations in the area. In August 2000 we settled the dispute and disposed of our assets for approximately $29 million, bringing to an end our activities in Russia.

In the third quarter of 1998, we began to implement a diversification program aimed at expanding the geographical scope of our business. We added three individuals to our Board of Directors who have international experience in the oil and gas industry. David Martin, who is now our Chairman, was formerly the President and CEO of Occidental Oil and Gas Corporation. E. Leon Daniel, who is now our President and CEO, and John Carver, who is now one of our directors, are also both former executives of Occidental Oil and Gas Corporation.

In August 1998, we began acquiring oil and gas exploration property interests in Peru, which we relinquished in 2000 after our exploration test well was unsuccessful.

In California, we started accumulating working interests and royalty interests in the San Joaquin Valley in 1998, primarily through an exploration agreement with Aera Energy LLC ("Aera"). This agreement entitled us to joint exploration rights with Aera in return for

analyzing and identifying oil and gas prospects. Under the agreement, we had access to exploration, seismic and technical data owned by Aera. See "Oil and Gas Properties — California".

In June 1999, we expanded the geographical scope of our business by acquiring Sunwing Energy Ltd. ("Sunwing"), an oil and gas company with operations in China. As a result of our merger with Sunwing, we acquired two production-sharing contracts with China National Petroleum Corporation ("CNPC") to develop and operate the Kongnan oilfield in Dagang, located in Hebei Province and the Zhaozhou oilfield in Daqing in the Heilongjiang Province. We subsequently sold our working interest in our Daqing oil and gas properties in January 2002 so we could concentrate our Chinese efforts in the larger and more prospective Dagang area. In April 2003, we received approval of our Overall Development Program ("ODP") for the Dagang field and in November 2003 we signed a heads of agreement with China International Trust & Investment Company ("CITIC") to jointly develop the Dagang oil project, operated by Sunwing. See "Oil and Gas Properties — China".

In April 2000, we acquired a limited volume license from Syntroleum Corporation ("Syntroleum") to use its proprietary GTL technology to convert natural gas into synthetic fuels. By sponsoring engineering and design work to extend the Syntroleum technology for large-scale and more economical gas conversion, we earned the right to upgrade our limited volume license to a master license. The master license allows us to use Syntroleum's proprietary process to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products. We plan to use the technology in areas with large natural gas deposits, which would otherwise be uneconomic to develop. Our master license was amended in June 2003 to remove all territorial restrictions, allowing us to use the Syntroleum proprietary process in an unlimited number of GTL projects throughout the world.

Immediately following the Syntroleum master license acquisition, we began actively pursuing development contracts for GTL plants in Qatar, Egypt and Oman and have undertaken extensive feasibility studies in connection with these opportunities. In December 2002, we formed a wholly owned subsidiary, GTL Japan Corporation ("GTLJ") to facilitate the participation of Japanese companies in GTL projects. In May 2003, advanced negotiations with Qatar Petroleum and the Qatari government to construct and operate a major GTL production facility in Qatar terminated without an agreement being reached. We continue to pursue several opportunities throughout the world to obtain rights to stranded natural gas deposits to use as feedstock for GTL projects including initiation, in August 2003, of a commercialization study in Bolivia. See "Gas-to-Liquids Projects".

In May 2000, we entered into an agreement with Discovery Operating, Inc. ("Discovery") to earn working interests in approximately 10,000 gross acres of oil and gas exploration properties in the Spraberry Trend of the West Texas Permian Basin in Midland County, Texas. We sold interests in the least productive of our Spraberry wells in 2002, limiting our remaining holdings to interests in 25 producing wells and approximately 2,500 gross acres. See "Oil and Gas Properties — Texas".

During 2000 and 2001, we leased the mineral rights in approximately 49,000 gross acres in the East Texas Basin and in 2001 entered into a joint venture agreement with a subsidiary of Unocal Corp. ("Unocal") to explore and develop prospects in the Bossier Trend. We subsequently farmed-out our interests in three wells drilled by Unocal and currently have mineral rights in approximately 33,200 gross acres. See "Oil and Gas Properties — Texas".

In February 2001, we extended our China interests. We entered into two memoranda of understanding with PetroChina Corporation ("PetroChina"), a subsidiary of CNPC, which gives us the exclusive right to negotiate production-sharing contracts for the development of oil and gas reserves in three blocks in the Sichuan Basin. In September 2002, we signed a 30-year production-sharing contract for two of these blocks covering approximately 900,000 acres and in October 2003 initiated the first phase of the exploration program. We are awaiting a response from PetroChina to begin negotiations on the third block. The Sichuan Basin is a major oil and gas-producing region of China located approximately 930 miles southwest of Beijing. See "Oil and Gas Properties — China".

In November 2003, we reached an agreement with Derek Resources (USA), Inc. ("Derek") to jointly develop the LAK Ranch field, a steam assisted gravity drainage project covering approximately 7,500 gross acres in the Powder River basin in Weston County, Wyoming. We will be the operator of the project and will earn an initial 30% working interest in the project by financing the capital cost of the pilot phase. Following the pilot phase, we will have the option to increase our working interest to 60% by providing additional capital toward the initial development phase for a total of $5 million, including the amounts spent on the pilot phase. See "EOR Projects — Wyoming".

In January 2004, we signed a Stock Purchase and Shareholders' Agreement with Ensyn Group, Inc. and its subsidiary, Ensyn Petroleum International Ltd. ("Ensyn"), to acquire a 10% equity interest in Ensyn and exclusive rights to use Ensyn's proprietary crude-oil upgrading process (the "Ensyn RTP™ Process") in several key international markets. We believe the Ensyn RTP™ Process technology offers excellent potential for commercializing heavy-oil fields throughout the world. See "EOR Projects — Ensyn".

CORPORATE STRATEGY

Our mission is to create shareholder value by finding and developing oil and gas reserves through the implementation of three main

strategies: (1) conventional exploration and production ("E&P") of oil and gas, primarily in the U.S. and China, (2) EOR development projects, and (3) monetization of stranded oil and gas reserves through the application of our licensed Syntroleum and Ensyn technologies. In pursuing these three business development areas, we are focused on achieving a balance in our short, medium and long-term goals. In the short term, we are focused on E&P and EOR projects that can be implemented and achieve early production and cash flow. Our medium term strategy is to concentrate on natural gas exploration and development and our long-term priority is on GTL production of ultra clean fuels. During 2003 these strategies continued to mature and gain focus.

Our short-term objective is to focus on areas where production can be achieved quickly and efficiently to create cash flow to fund our operations and allow us to pursue our medium and long-term objectives. To date, we have established oil and natural gas production in the South Midway property in the San Joaquin Basin of California, in the Spraberry Trend of West Texas and at Dagang in China.

One of the key elements of our medium term strategy is exploration and development in the San Joaquin Basin of California and in East Texas. In 1998, we acquired exploration rights through an agreement with Aera, California's largest producer. This agreement gave us access to a significant inventory of exploration, seismic and technical data for the purpose of identifying drillable prospects, primarily beneath existing oil fields in the San Joaquin Basin. We recently farmed into the Sledge Hamar prospect, a property at the southern extension of the South Belridge field, and Knights Landing, in northern California, where we will fund a gathering system for four recent gas discovery wells and plan to participate in drilling additional appraisal and exploration wells in the lease block.

Our activities in China also have the potential to contribute to our medium-term growth. Sunwing has commenced the development phase and has established crude oil production in the Kongnan oilfield in Dagang, Hebei Province. We remain encouraged by the results achieved in our pilot phase production program and have commenced the active drilling and development phase of the project. In September 2002, Sunwing entered into a 30-year production-sharing contract with PetroChina in the western portion of the Sichuan Basin. Under the terms of the agreement, Sunwing will develop natural gas deposits on the 900,000 acre Zitong Block. The first three-year exploration phase has begun with seismic activity. For a further description of our E&P projects in the U.S. and China, see "Oil and Gas Properties".

Our recently signed Stock Purchase and Shareholders' Agreement with Ensyn Group, Inc. and Ensyn will give us exclusive rights to use Ensyn's proprietary crude-oil upgrading process in several key oil producing countries. We believe the Ensyn RTP™ Process technology offers excellent potential for commercializing heavy-oil fields throughout the world. See "EOR Projects — Ensyn".

Our long-term objective is to become a leader in the development and operation of GTL projects. We foresee rapidly increasing future demand for clean energy as environmental regulations become more stringent and the world's crude oil becomes more sour and heavy. We believe that Syntroleum's proprietary GTL technology holds significant potential for the economic production of synthetic fuels and other specialty petroleum products from stranded natural gas deposits throughout the world, which would otherwise be uneconomic to exploit. Although there are several competing GTL technologies under development, we believe that the Syntroleum technology offers several key advantages. Plant construction is less expensive and the plant is safer to operate because, unlike competing technologies, the conversion process utilizes compressed air rather than pure oxygen.

With our master license to use Syntroleum's proprietary GTL technology, we are currently pursuing opportunities in Qatar, Egypt and Bolivia to obtain rights to stranded natural gas deposits to use as feedstock for GTL projects.

OIL AND GAS PROPERTIES

Our primary oil and gas properties are located in the San Joaquin Valley area of California, the Midland and East Texas Basins in Texas and the Hebei and Sichuan Provinces in China. Set forth below is a description of our material oil and gas properties.

California

Over the past six years, we have acquired interests in a number of properties in and around the San Joaquin Basin. To date, only our South Midway project contains proved reserves and has wells on production. During the first quarter of 2004, we established initial production at the Citrus and Sledge Hamar prospects in the San Joaquin Valley. The commerciality of these two new projects is currently under evaluation. We cannot assure you that any of our other prospects in California will result in the development of commercially viable production.

Aera Exploration Agreement

In 1998, we acquired rights to an exploration agreement with Aera covering an area of more than 250,000 acres in the San Joaquin Valley. The Aera exploration agreement gave us access to all of Aera's exploration, seismic and technical data in the region for the purpose of identifying drillable exploration prospects within the exclusive area. Using the extensive proprietary seismic and technical databases owned by Aera and supplemented by us, we have identified 30 prospects within 12 prospect areas of mutual interest

("AMIs") covering approximately 76,000 gross acres. Of the 12 prospect AMIs we have submitted, Aera has elected to take a working interest in 9 areas, in which we have working interests ranging from 12.5% to 50% and we have a 100% working interest in three prospect AMIs in which Aera elected not to participate. We will continue to hold exploration rights to the lands within previously designated and accepted prospect AMIs until an exploration well is drilled in that prospect. Once we identify a drillable prospect and agree upon working interests with Aera, we have an indefinite time to carry out exploration drilling if Aera elects to participate in the prospect. If Aera elects to participate but not to drill the designated prospect, or elects not to participate, we have an additional two years to drill the prospect on our own or with other parties. This two-year period will be extended as long as we continue to drill or have established production.

- ***South Midway***

In 2003, we drilled 17 wells in the southern expansion area of South Midway, 15 of which are producing wells. In addition to the recent drilling activity, facilities were expanded in 2003 to gather, test and cycle-steam the new production. A steam generator was purchased and installed to accelerate the steam stimulation of producing wells and reduce leasing costs. Pending continuation of the favorable response to steam, it is anticipated that the second phase of the drilling program in the southern expansion will begin in the second quarter of 2004 with the drilling of approximately 12 additional wells.

By the end of 2003, production averaged 460 net Bopd from 51 producing wells, including 140 Bopd from the southern expansion. Cyclic steaming operations are in the early stages and peak production for the project is expected to occur by mid-year 2005. In addition to drilling new wells, we are evaluating the potential for production gains that may be achieved by switching to a continuous steam application process that could double the recovery expected from the current cyclic application process. We are the operator in South Midway Sunset, with a 100% working interest and a 93% net revenue interest.

- ***Citrus***

The Citrus prospect is located in the southern extension of the currently producing Lost Hills field, which is unrelated to our deep-gas prospect at Northwest Lost Hills, 15 miles to the north. We acquired an interest in more than 2,500 potentially productive acres offsetting the Lost Hills field, where there has been recent development drilling. We are the operator and own interests ranging between 83% and 100% in the prospect leases.

In December 2003, we completed drilling operations at Citrus #1, our first horizontal well in this prospect. A total horizontal section of more than 1,900 feet was drilled at a vertical depth of 7,750 feet in the Antelope Shale formation, an important producing zone to adjacent offsetting production wells. This is our first well on the southeastern nose of the Lost Hills Antelope field. The well is currently on production and we will consider a second horizontal completion after our evaluation of the current production data.

- ***Northwest Lost Hills***

The Northwest Lost Hills #1-22 well, operated by Aera, began drilling in August 2001. The well was designed to fully evaluate the natural gas and condensate reserve potential of the deep Temblor formation and reach a depth of approximately 20,000 feet. This drilling objective was achieved in August 2002 after substantial delays and cost overruns resulting from difficult drilling conditions. While drilling the well, we encountered several high-pressure intervals, which indicated the presence of natural gas and decided to set casing in preparation for testing. In 2003, the well was temporarily abandoned pending the identification of one or more partners to share the costs of the testing program. Temporary abandonment is expected to permit reentering the well at a later date for testing. Until it is tested, the well's commercial potential, if any, cannot be determined. Of the 8,500 gross acres encompassing the Northwest Lost Hills prospect, we hold, on average, a 39% working interest. We have a 42% working interest in the Northwest Lost Hills #1-22 well. If, as and when we identify a partner to fund a test of the well's commercial potential, our working interest is expected to decrease by up to 50%.

- ***Belgian Anticline***

We drilled the first well in this prospect in 2001 and found the prospective gas sands, but they had been partially depleted by other nearby wells. A second well in this prospect is contemplated in late 2004. We have a 40% working interest in this prospect and Aera is the operator.

Other California Prospects

- ***North South Forty***

In 1999, we entered into an agreement with Prime Natural Resources, LLC ("Prime") to jointly conduct a 3-D seismic survey in the southern San Joaquin Valley basin in order to identify new prospects over an area of approximately 80,000 acres. We subsequently

entered into an exploration agreement with Prime and Aera in which we agreed to pool certain of our acreage positions in the basin to share the costs of carrying out the 3-D seismic program and to broaden our respective interests in the area. The agreement with Prime and Aera expired in June 2003. Any acreage contributed by the parties for which no drillable prospects had been identified has either reverted back to the contributing party or the leases have been allowed to expire. We currently have working interests from 17.5% to 50% in approximately 19,600 gross acres.

Based on the results of the 3-D seismic interpretation, we plan to drill three wells in the first half of 2004 with Prime. Our working interests in these wells will be 50%.

- ***Sledge Hamar***

In November 2003, we farmed into the Sledge Hamar prospect, which is located in a 900-acre block at the southern extension of the South Belridge Field. The operator Nahabedian Exploration Group ("NEG") drilled the first well, Sledge Hamar 1-7, in December 2003. The well reached a total depth of 5,704 feet and encountered strong shows of oil and gas in several intervals of the Stevens sand, which is a major oil-producing formation in the San Joaquin Valley. The well is currently on production and plans to appraise this new pool discovery are under consideration for later in 2004. We hold a 40% working interest in the prospect.

- ***Knights Landing***

In February 2004, we farmed into the Knights Landing project, which is a 14,000-acre block located in the Sutter and Yolo counties, in northern California, operated by NEG. Under this exploration and development farm-in agreement, we purchased, for $1.0 million, a 50% interest in four recent discoveries by NEG in the contract area and agreed to fund, for $0.6 million, gas gathering, surface treatment facilities and meters to connect the four wells to an existing pipeline system. The agreement also provides for us to participate, at our election, in drilling additional exploration wells in the lease block. The primary objective of this development and exploration program is the Starkey Sand formation, which is an established producing reservoir in the region that lies between depths of 2,000 and 3,500 feet. After payout, we will hold a 50% working interest in the project.

Texas

- ***Spraberry***

This producing property is located on 2,500 gross acres in the Spraberry Trend of the West Texas Permian Basin in Midland County, Texas, which we acquired in 2002 through a farm-in from Discovery. After selling a portion of our working interests in 2002 for approximately $3 million, we retain working interests ranging from of 31% to 48% in 25 wells which are currently producing approximately 100 net Boe/d. Discovery is the operator.

- ***East Texas***

During 2000 and 2001, we acquired mineral rights in approximately 49,000 gross acres in East Texas under a joint venture with Unocal. Unocal, as operator of the joint venture, was to fund the drilling costs for the first several exploration wells to offset the $10.1 million in leasehold, seismic and processing costs we incurred to acquire the mineral rights. After our respective investments in the joint venture have been equalized, we are to share exploration, development and infrastructure costs equally.

Unocal subsequently drilled three wells on the Creslenn Ranch and Lone Star prospects at a cost of $8.5 million. During drilling, indications of natural gas were encountered from multiple pay sands such as the Bossier, Cotton Valley and Pettit but no commercial levels of production were established. As a result, Unocal elected to defer any further activity under the joint venture and we have been seeking other parties to join and fund drilling and workover activities on this acreage.

In 2003, we farmed out our interests in two wells drilled by Unocal in the Creslenn Ranch prospect to Perryman Exploration Partners ("Perryman") to test the shallower zones in the wells. A successful gas recompletion was made in the first well in July 2003 from the Pettit limestone. At the end of 2003, the well was flowing at a rate of 400 gross Mcf per day. Perryman has recompleted the second Creslenn Ranch well to test the Pettit zone and recovered oil, gas and water. Perryman is considering further testing of this zone or testing a shallower zone to establish commercial production in this well. Ivanhoe will retain a 30% working interest after payout in these wells and a 50% working interest in the remaining acreage.

In 2003, we farmed out our interest in the third well drilled by Unocal in the Lone Star prospect to Kraker Martin Energy LLC ("Kraker"). Kraker recompleted the well in the Cotton Valley sandstone formation and testing was completed with no commercial production established. We retain a 12 ½ percent working interest in the well, which will increase to 25% after payout.

In November 2003, we farmed out our interest in the Catfish Creek prospect to Perryman. Perryman is required to drill an 11,000 foot

well in the second quarter of 2004 to test the Rodessa and Pettit formations. We will retain a 25% working interest after payout in this prospect and surrounding acreage.

We currently own mineral rights in approximately 33,200 gross acres in East Texas but do not plan to renew leases as they expire except in the Creslenn Ranch, Catfish Creek and Malakof prospects which combined contain approximately 15,200 gross acres. We plan to drill an exploration well in the Malakoff prospect in 2004.

China

We hold interests in China through our wholly-owned subsidiary Sunwing Energy Ltd.

- ***Dagang Project***

Sunwing's producing property in China is a 30-year production-sharing contract with CNPC, covering an area of 22,400 gross acres divided into six blocks in the Kongnan oilfield in Dagang, Hebei Province, China (the "Dagang Project"). Under the contract we operate the project and fund 100% of the development costs to earn 82% of the net revenue from oil production until cost recovery, at which time our entitlement reverts to 49%.

The contract stipulates that we have the right to market our oil domestically or export it, sell our product in U.S. dollars and receive world market prices for our product. We are currently selling our crude oil to CNPC at a three-month rolling average price of Cinta crude oil, which over the past three years has averaged approximately $2.00 per barrel less than the West Texas Intermediate ("WTI") price. Cinta is an Indonesian crude that is traded daily on the international oil market.

All petroleum producers in China pay a value added tax of 5% on oil production. We pay no royalty until annual gross production of crude oil from a particular block within the Dagang Project exceeds 500,000 tonnes per annum. Royalties then become payable at a rate of 2% and increase incrementally as the rate of production increases to a maximum of 12.5% once annual gross production on a block exceeds four million tonnes. Our entire interest in the Dagang Project will revert to CNPC at the end of the 20-year production phase of the contract or if we abandon the project earlier.

During 2001, we completed the pilot phase and in 2002 submitted the final draft of an Overall Development Program ("ODP") to Chinese regulatory authorities for approval. Final Government approval was obtained in April 2003, after which the development phase commenced. The current development program is expected to cost approximately $198 million over a three-year period and is expected to involve drilling 115 new wells and reworking an additional 28 of the 82 existing wells.

In January 2004, we signed a farm-out agreement with Richfirst Holdings Limited ("Richfirst"), a wholly-owned subsidiary of CITIC, whereby Richfirst will acquire a 40% working interest in the Dagang project in consideration for an up-front payment of $20 million. The transaction is subject to approval from CNPC and relevant Chinese Government Authorities, which is expected in the first quarter of 2004. Richfirst will have the right to exchange its working interest in the Dagang project for common shares in Sunwing, should we obtain a public listing for Sunwing, or for common shares in Ivanhoe. CITIC also has committed to assist in arranging non-recourse project financing for the remainder of the Dagang development program.

- ***Sichuan Basin***

In February 2001, we signed two memoranda of understanding with PetroChina. These memoranda gave us the exclusive right to negotiate production-sharing contracts for three land blocks in the Sichuan province. We agreed with PetroChina to carry out joint feasibility studies on the Zitongxi, Zitongdong and Yudong blocks. These blocks, located in the Sichuan Basin, approximately 930 miles southwest of Beijing cover an area of approximately 2.2 million acres. PetroChina has drilled 39 wells on the three blocks, with twenty-six of these wells having been classified as gas wells. PetroChina has production tested 8 of the estimated 38 hydrocarbon bearing structures located on the three blocks. In September 2002, we signed a production-sharing contract ("the Zitong Contract"), with PetroChina covering both the Zitongxi and Zitongdong blocks. The contract received final Chinese regulatory approval in November 2002.

Under the Zitong Contract, Sunwing has agreed to conduct an exploration program on the Zitong block consisting of two phases, each three years in length. The parties will jointly participate in the development and production of any commercially viable deposits, with production rights limited to a maximum of the lesser of 30 years following the date of the Zitong Contract or 20 years of continuous production.

During the first phase of exploration, Sunwing must complete a minimum work program consisting of reprocessing 2,000 kilometers of seismic data, completing 500 additional kilometers of new seismic lines and drilling and completing two wells totaling at least 7,000 meters, with estimated minimum expenditures for the program of at least $18 million. Upon completion of the first phase,

Sunwing must relinquish up to 30% of the Zitong block. During 2003, we reprocessed 2,500 kilometers of existing seismic data and commenced contract negotiations for just over 1,000 kilometers of new 2-D seismic. The contract was signed in January 2004 and fieldwork commenced at that time.

During phase two, Sunwing must complete a minimum work program consisting of new seismic lines totaling 350 kilometers and drill and complete two additional wells totaling 7,000 meters, with estimated minimum expenditures for the program of at least $16 million. Following the completion of phase two, Sunwing must relinquish all of the property except any areas identified for development and production.

Sunwing can elect to commence the development of commercially viable deposits at any time following the submission of an ODP. Once Sunwing completes phase one of the exploration project, Sunwing can also elect not to proceed with phase two of the exploration project. However, once Sunwing commences a phase of the exploration project it must complete the minimum work program or else it will be obligated to pay, to PetroChina, the cash equivalent of the deficiency in the work program for that exploration phase.

If Sunwing identifies a field for development and/or production, the parties will divide the participating interest in the project, with PetroChina entitled to fund and take up to 51% of the participating interest and Sunwing funding and taking the balance.

Once commercial production commences, Sunwing will recover annual exploration, development and operating costs from up to 60% of gross oil production and 70% of gross natural gas production. After annual cost recovery, Sunwing is entitled to production equaling its participating interest, subject to certain additional rights of the Chinese government. Assuming Sunwing holds a 49% participating interest, Sunwing will be entitled to approximately 75% of production initially, declining to approximately 45% after full exploration and development cost recovery.

PetroChina retains the rights to production from six existing wells located on the Zitong Block. Sunwing can drill new wells on the same structure as those tapped by the existing wells, but Sunwing's wells must be no closer than 1,000 meters from the existing wells.

In 2003, we established an office in Chengdu, the capital of Sichuan. We have also completed our feasibility study obligations for the Yudong block and submitted a report to PetroChina in April 2002. In September 2002, we submitted a letter of intent to negotiate a production-sharing contract and our work plan for the Yudong block, and are currently awaiting PetroChina's reply.

- ***CITIC Alliance***

In October 2002, Sunwing entered into an agreement with CITIC Energy Ltd ("CITIC Energy") to form a strategic alliance to seek out and develop oil and gas projects in China and around the world. CITIC Energy is a subsidiary of CITIC, a major Chinese state-owned enterprise that holds interests in a wide range of industries.

Under the terms of the agreement, CITIC Energy will assist Sunwing in raising its profile in Asian capital markets and gaining access to future financing opportunities. CITIC Energy will also support Sunwing in its plan to obtain a listing for its shares on the Stock Exchange of Hong Kong.

Sunwing is expected to assist CITIC Energy in identifying and acquiring interests in international oil and gas development projects and in introducing GTL and other advanced energy-sector technologies to China's domestic oil and gas industry. We hold a master license to Syntroleum's proprietary GTL process, the geographical scope of which includes China.

CITIC Energy has also agreed to assist Sunwing in its efforts to negotiate a production-sharing contract with PetroChina covering the Yudong block in Sichuan Province. Should a production-sharing contract for the Yudong block be obtained, Sunwing and CITIC Energy will jointly participate in the development of the project on a 70/30 basis. Within 180 days thereafter, either party can elect to convert CITIC Energy's 30% participating interest in the project into a 20% equity interest in Sunwing. CITIC Energy has the right to appoint a representative to Sunwing's board of directors and will be entitled to appoint a second representative if, as and when it acquires a 20% equity interest in Sunwing.

In April 2003, we entered into a further agreement with CITIC Energy that enables both companies to form a global strategic alliance to investigate, explore and develop oil, natural gas, metallurgical coal, liquefied natural gas and GTL projects in China and around the world, to help supply China's future energy requirements. The new agreement builds upon the initial partnership formed between the two companies in October 2002 and follows discussions both between the two companies and with asset owners of potential projects in China and in other parts of the world.

- ***Daqing Project***

In 2002, we sold our Daqing project and retained an overriding royalty interest of 4% before cost recovery and 2% thereafter. During 2003, the operator undertook further development of the field increasing our royalty revenues from $0.1 million in 2002 to $0.4 million in 2003.

EOR PROJECTS

Ensyn

In January 2004, we signed a Stock Purchase and Shareholders' Agreement with Ensyn Group, Inc. and Ensyn pursuant to which we acquired a 10% equity interest in Ensyn and exclusive rights to use the proprietary Ensyn RTP™ Process in several key international markets. We have agreed to pay Ensyn $2.0 million and to grant Ensyn the right to acquire an equity interest in each international oil development project in which we use the Ensyn RTP™ Process. The purchase price will be paid in four installments and completion of the acquisition is subject to the attainment of specific milestones: (1) upon signing the heads of agreement, (2) upon signing the Stock Purchase and Shareholders' Agreement, (3) upon Ensyn delivering a commercial demonstration facility to California and (4) upon confirmation of the economic viability of the Ensyn RTP™ Process from the commercial demonstration facility.

The Ensyn RTP™ Process upgrades the quality of heavy oil by producing lighter, more valuable crude oil. Ensyn reports that this process yields up to a three-fold economic improvement in heavy-oil projects. The heaviest hydrocarbon fraction is consumed as fuel to generate the steam used to enhance recovery of heavy crude. This lowers costs by reducing or eliminating the need to purchase high-priced natural gas for steam generation and improves revenue since the higher quality light-crude fraction can be sold at higher prices. The lighter crude has improved viscosity that permits more efficient pumping through pipeline networks and significantly reduces transportation costs to marketing points. The Ensyn RTP™ Process uses readily available plant and process components. The technology already has been successfully applied to continuous wood/biomass processing, with several commercial plants in operation in Canada and the U.S. An Ensyn pilot plant in Ontario, Canada, has completed more than 90 test runs on heavy oil.

We will have exclusive rights to use the Ensyn RTP™ Process in China, Mongolia, Iraq, Oman and all countries in South America except Venezuela. In these countries, our rights will be exclusive for an initial term of five years subject to extension if and when commercial applications develop. We will have non-exclusive rights to the process in other countries.

For each project we develop using the Ensyn RTP™ Process, Ensyn may elect to receive a royalty or an equity participation in the project of no more than 10%, except for each such project that we develop in South America, other than in Venezuela and Peru, where Ensyn may elect to receive an equity interest equal to 25% of our interest.

In June 2003, both companies entered into a contract to evaluate the Ensyn RTP™ Process on heavy crude oil produced from our South Midway field, in a 250-barrel-per-day commercial demonstration facility now being built by Ensyn in the San Joaquin Valley, California.

Wyoming

- ***LAK Ranch***

In January 2004, we signed farm-in and joint operating agreements with Derek for the joint development of the LAK Ranch field, a thermal recovery/horizontal well oil project in Weston County, Wyoming. The LAK Ranch field covers approximately 7,500 acres in Wyoming's Powder River basin.

Under the terms of the joint operating agreement, we will be the operator of the project and will earn an initial 30% working interest by financing the capital cost of the pilot phase. Following the pilot phase, we will have the option to increase our working interest to 60% by providing additional capital toward the initial development phase for a total of $5.0 million, including the amounts spent on the pilot phase. Thereafter, all future capital expenditures are to be shared on a working-interest basis. Should we elect not to proceed beyond the pilot phase our working interest will be reduced to 15% and Derek will become the operator.

To date, Derek has completed a steam-assisted-gravity-drainage well pair to a depth of 1,000 feet and 1,800 feet horizontally into the Newcastle Sand formation. Surface steam-injection and oil-recovery equipment are in place. Extensive testing indicates that because of the viscosity of the oil, production can be expected to respond favorably to the application of continuous heat through steam injection. Surface preparations for the pilot phase are underway and steaming operations are expected to begin before the end of the first quarter of 2004. Initially, steam will be injected into the existing horizontal well and production is expected to commence shortly thereafter. By the fourth quarter of 2004, five vertical steam-injection wells are expected to be drilled, providing continuous steam application to the reservoir and increasing production volumes from the horizontal production well. We also plan a high-resolution

3-D seismic data acquisition program to further identify the limits of the field.

Assuming a successful pilot phase, the initial development phase is expected to include additional horizontal production wells, new steam-injection wells (vertical or horizontal) and expansion of surface facilities. We estimate that the initial development phase could grow to more than 20 wells.

GAS-TO-LIQUIDS PROJECTS

Syntroleum License

We hold a non-exclusive master license entitling us to use Syntroleum's proprietary GTL process in an unlimited number of projects with no limit on production volume. In June 2003, we gave up our rights for license fee credits for the $10.0 million we paid for the master license and $2.0 million we invested in Syntroleum's Sweetwater project. In consideration, Syntroleum removed certain territorial restrictions to our master license, which will enable us to pursue GTL project opportunities worldwide, particularly in China. Syntroleum has also agreed that, in respect of GTL projects in which both companies participate, no additional license fees or royalties will be payable and that Syntroleum will also contribute to any such project the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but we would be required to pay the normal license fees and royalties in such projects.

Syntroleum Process

Syntroleum's proprietary GTL process is designed to catalytically convert natural gas into synthetic liquid hydrocarbons. This patented process uses compressed air, steam and natural gas as initial components to the catalyst process. As a result, this process (the "Syntroleum Process") substantially reduces the capital and operating cost and the minimum economic size of a GTL plant as compared to the other oxygen-based GTL technologies.

Syntroleum developed its GTL technology based on a process developed in Germany in the 1920s for the gasification of coal into oil, called the Fischer-Tropsch reaction. Syntroleum has applied its principles to the conversion of natural gas to synthetic liquid hydrocarbons. Syntroleum believes that it holds a competitive advantage over other GTL technologies because the Syntroleum Process uses air when converting natural gas into synthetic hydrocarbons. Competitor GTL processes use either steam reforming or a combination of steam reforming and partial oxidation with pure oxygen. A steam reformer and an air separation plant necessary for oxidation are expensive and hazardous and increase operating costs.

From our perspective, the attraction of the Syntroleum Process lies in the commercialization of stranded natural gas. Such gas exists in discovered and known reservoirs, but requires innovative gas processing to produce products that can be marketed on an economic basis. Operators consider natural gas to be stranded based on the relative size of the fields and their remoteness from comparable sized markets.

GTL Prospects

During 2001, we undertook detailed project feasibility studies for the construction, operation and cost of GTL plants in both Qatar and Egypt. The scope of our proposed project in Qatar included the development of natural gas from the North Field, transporting that gas to shore, extracting the associated liquids in a natural gas liquids ("NGL") plant, moving the "dry" gas though the GTL facility to create diesel and naphtha and storing and offloading the products for shipment throughout the world. In May 2003, advanced negotiations with Qatar Petroleum and the Qatari government to construct and operate such a facility terminated without an agreement being reached. In the quarter ended June 30, 2003, we wrote down $3.3 million of our GTL investments for expenditures incurred in connection with these negotiations.

The feasibility studies we have undertaken for Egypt contemplate the natural gas feedstock being purchased, rather than developed. A preliminary feasibility study for a 45,000 barrels per day fuels, specialty products and lubricants GTL plant in Egypt was completed and presented to the government of Egypt and its agencies responsible for the development and monetization of its natural gas reserves. We await the approval of our scope of work for a commercialization study and the finalization of a heads of agreement authorizing the commercialization study and setting aside sufficient natural gas reserves for a 45,000 barrels per day GTL plant.

We have conducted marketing and transportation feasibility studies for both Europe and Asia Pacific regions in which we identified potential markets and estimated premiums for GTL diesel and GTL naphtha. Based on our ongoing commercialization studies and the growing demand for cleaner sources of energy in Japan, we incorporated GTLJ to facilitate the potential future participation by Japanese companies in GTL projects. Should we be successful in obtaining the rights to develop such projects, we intend to assign up to 5% of our interest to GTLJ. We would then invite Japanese companies from the refining and distribution, exploration and production, and trading and manufacturing industry sectors to invest in GTLJ. The proceeds raised would be used to fund a portion of

project costs, including front-end engineering and design.

In July 2003, we signed an agreement with Repsol-YPF Bolivia S.A. ("Repsol") and Syntroleum that brings us into a study to build a 90,000-barrel-per-day GTL plant in southern Bolivia. The commercialization study includes an analysis of alternative plant sites, transportation logistics and screening economics conducted by representatives from Ivanhoe, Repsol and Syntroleum. The initial phase of the commercialization study is expected to be completed in the first quarter of 2004 at which time the decision is expected to be made whether or not to proceed to the final phase of the commercialization study. Upon determination that the project is economically feasible and meets financing requirements, the three parties are expected to enter into discussions regarding a joint-venture agreement prior to undertaking definitive engineering and design work.

RISK FACTORS

We are subject to a number of risks due to the nature of the industry in which we operate, the present state of development of our business and the foreign jurisdictions in which we carry on business. The following factors contain certain forward-looking statements involving risks and uncertainties. Our actual results may differ materially from the results anticipated in these forward-looking statements.

We have a history of losses and must generate greater revenue to achieve profitability.

We commenced operations in 1997 and have been involved in three start-up situations in Russia, China and the U.S. Like most start-up companies we have incurred losses during our start-up activities. Our current cash flows alone are insufficient to fund our medium and long-term business plans, necessitating further growth and funding for implementation. We may be unable to achieve the needed growth to obtain profitability and may fail to obtain the funding that we need when it is required.

We are not able to guarantee the successful commercial development of our licensed "gas-to-liquids" technology.

To date, no commercial-scale GTL plants have been constructed using the proprietary GTL process we license from Syntroleum and, therefore, the process has not been proven on a commercial scale. Other developers of GTL technology have significantly more financial resources than Ivanhoe and may be able to use this to obtain a competitive advantage.

We may not be able to conclude a GTL development and production-sharing contract.

We were unsuccessful in concluding a GTL development and production-sharing contract in Qatar and we can give no assurances as to when or if we will be able to conclude such contracts in Egypt, Bolivia or other countries where we are now, or will be, exploring GTL project opportunities.

Conflict in the Middle East may hamper our GTL project objectives.

Ongoing tensions and conflict in the Middle East could harm our business in the short to medium term by making it difficult or impossible to continue our pursuit of GTL projects in the region or to obtain financing for projects we do succeed in obtaining. It is impossible to predict the occurrence of such events, how long they will last, the economic consequences of the conflict for the energy industry, regionally and globally, and how our business might be affected over the longer term.

Crude oil and natural gas prices are volatile.

Fluctuations in the prices of oil and natural gas will affect many aspects of our business, including our revenues, cash flows and earnings; our ability to attract capital to finance our operations; our cost of capital; the amount we are able to borrow and the value of our oil and natural gas properties.

Both oil and natural gas prices are extremely volatile. Oil prices are determined by international supply and demand. Political developments, compliance or non-compliance with self-imposed quotas, or agreements between members of the OPEC can affect world oil supply and prices. Any material decline in prices could result in a reduction of our net production revenue and overall value. The economics of producing from some wells could change as a result of lower prices. As a result, we could elect not to produce from certain wells. Any material decline in prices could also result in a reduction in our oil and natural gas acquisition and development activities.

In addition, a material decline in oil and natural gas prices from historical average prices could adversely affect our ability to borrow and to obtain additional capital on attractive terms.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause

disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploration projects.

Government regulations in foreign countries may limit our activities and harm our business operations.

In addition to our interest in our China projects, we may enter into contractual arrangements to acquire oil and gas properties in other foreign jurisdictions with governments, governmental agencies or government-owned entities. The foreign legal framework for these agreements, particularly in developing countries, is often based on recent political and economic reforms and newly enacted legislation, which may not be consistent with long-standing local conventions and customs. As a result, there may be ambiguities, inconsistencies and anomalies in the agreements or the legislation upon which they are based which are atypical of more developed western legal systems and which may affect the interpretation and enforcement of our rights and obligations and those of our foreign partners. Local institutions and bureaucracies responsible for administering foreign laws may lack a proper understanding of the laws or the experience necessary to apply them in a modern business context. Foreign laws may be applied in an inconsistent, arbitrary and unfair manner and legal remedies may be uncertain, delayed or unavailable.

We may not be successful in negotiating additional production sharing contracts in China.

We hold our interests in China through two production-sharing contracts with CNPC for the Dagang and Zitong blocks. We also have a memorandum of understanding with PetroChina indicating a mutual intention to negotiate an additional production-sharing contract in the Sichuan basin. We cannot assure you, based on our existing memorandum of understanding with PetroChina, that we will successfully negotiate additional production-sharing contracts. It is possible that disputes between us could arise in the future, which must be resolved under foreign law. We cannot be sure that we can enforce our legal rights in foreign countries or that an effective legal remedy will be available to us in any dispute governed by foreign law.

We might not be successful in acquiring and developing new prospects and our exploration and development properties may not contain any significant proved reserves.

Our future exploration and development success depends upon our ability to find, develop and acquire additional economically recoverable oil and natural gas reserves. The successful acquisition and development of oil and gas properties requires proper forecasting of recoverable reserves, oil and gas prices and operating costs, potential environmental and other liabilities and productivity of new wells drilled.

Estimates of cost to explore, develop and produce are assessments and are inexact. As a result, we might not recover the purchase price of a property from the sale of production from the property, or might not recognize an acceptable return from properties we acquire. Our estimates of exploration, development and production costs can be affected by such factors as permitting regulations and requirements, weather, environmental factors, unforeseen technical difficulties and unusual or unexpected formations, pressures and work interruptions.

Exploration and development involves significant risks. Few wells, which are drilled, are developed into commercially producing fields. Substantial expenditures may be required to establish the existence of proved reserves, and we cannot assure you commercial quantities of oil and gas deposits will be discovered sufficient to enable us to recover our exploration and development costs or be sufficient to sustain our business.

Expansion of our operations will require significant capital expenditures for which we may be unable to provide sufficient financing. Our need for additional capital may harm our financial condition.

We will be required to make substantial capital expenditures far beyond our existing capital resources to develop a GTL project, exploit our existing reserves and to discover new oil and gas reserves. Historically, we have relied, and continue to rely, on external sources of financing to meet our capital requirements to continue acquiring, exploring and developing oil and gas properties and to otherwise implement our corporate development and investment strategies. We have, in the past, relied upon equity capital as our principal source of funding. We plan to obtain the future funding we will need through debt and equity markets, but we cannot assure you that we will be able to obtain additional funding when it is required and whether it will be available on commercially acceptable terms. We also make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs may increase substantially. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable opportunities to acquire new oil and gas properties or default on existing funding commitments to third parties and forfeit or dilute our rights in existing oil and gas property interests. Our limited operating history may make it difficult to obtain future financing.

You should not unduly rely on reserve information because reserve information represents estimates.

Reserve estimates involve a great deal of uncertainty, because they depend in large part upon the reliability of available geologic and engineering data, which is inherently imprecise. Geologic and engineering data are used to determine the probability that a reservoir of oil and natural gas exists at a particular location, and whether oil and natural gas are recoverable from a reservoir. Recoverability is ultimately subject to the accuracy of data including, but not limited to geological characteristics of the reservoir structure, reservoir fluid properties, the size and boundaries of the drainage area and reservoir pressure and the anticipated rate of pressure depletion.

The evaluation of these and other factors is based upon available seismic data, computer modeling, well tests and information obtained from production of oil and natural gas from adjacent or similar properties, but the probability of the existence and recoverability of reserves is less than 100% and actual recoveries of proved reserves usually differ from estimates.

Reserve estimates also require numerous assumptions relating to operating conditions and economic factors, including, among others the price at which recovered oil and natural gas can be sold, the costs of recovery, prevailing environmental conditions associated with drilling and production sites, availability of enhanced recovery techniques, ability to transport oil and natural gas to markets and governmental and other regulatory factors, such as taxes and environmental laws.

A negative change in any one or more of these factors could result in quantities of oil and natural gas previously estimated as proved reserves becoming uneconomic. For example, a decline in the market price of oil or natural gas to an amount that is less than the cost of recovery of such oil and natural gas in a particular location could make production thereof commercially impracticable. The risk that a decline in price could have that effect is magnified in the case of reserves requiring sophisticated or expensive production enhancement technology and equipment, such as some types of heavy oil. Each of these factors, by having an impact on the cost of recovery and the rate of production, will also affect the present value of future net cash flows from estimated reserves.

In addition, estimates of reserves and future net cash flows expected from them prepared by different independent engineers, or by the same engineers at different times, may vary substantially.

Information in this document regarding our future plans reflects our current intent and is subject to change.

We describe our current exploration and development plans in this document. Whether we ultimately implement our plans will depend on availability and cost of capital; receipt of additional seismic data or reprocessed existing data; current and projected oil or gas prices; costs and availability of drilling rigs and other equipment, supplies and personnel; success or failure of activities in similar areas; changes in estimates of project completion costs; our ability to attract other industry partners to acquire a portion of the working interest to reduce costs and exposure to risks and decisions of our joint working interest owners.

We will continue to gather data about our projects and it is possible that additional information will cause us to alter our schedule or determine that a project should not be pursued at all. You should understand that our plans regarding our projects might change.

Our business may be harmed if we are unable to retain our licenses, leases and working interests in licenses and leases.

Some of our properties are held under licenses and leases and working interests in licenses and leases. If we, or the holder of the license or lease, fail to meet the specific requirements of each license or lease, the license or lease may terminate or expire. We cannot assure you that any of the obligations required to maintain each license or lease will be met. The termination or expiration of our licenses or leases or our working interest relating to a license or lease may harm our business. Some of our property interests will terminate unless we fulfill certain obligations under the terms of our agreements related to such properties. If we are unable to satisfy these conditions on a timely basis, we may lose our rights in these properties. The termination of our interests in these properties may harm our business.

Complying with environmental and other government regulations could be costly and could negatively impact our production.

Our operations are governed by numerous laws and regulations at various levels of government in the countries in which we operate. These laws and regulations govern the operation and maintenance of our facilities, the discharge of materials into the environment and other environmental protection issues. The laws and regulations may, among other potential consequences, require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; require that reclamation measures be taken to prevent pollution from former operations; require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remediating contaminated soil and groundwater and require remedial measures be taken with respect to property designated as a contaminated site, for which we are a responsible person.

Under these laws and regulations, we could be liable for personal injury, clean-up costs and other environmental and property

damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages as well as environmental damage that occurs over time. However, we do not believe that insurance coverage for the full potential liability of environmental damages is available at a reasonable cost. Accordingly, we could be liable, or could be required to cease production on properties, if environmental damage occurs.

The costs of complying with environmental laws and regulations in the future may harm our business. Furthermore, future changes in environmental laws and regulations could occur that result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, any of which could have a material adverse effect on our financial condition or results of operations.

We compete for oil and gas properties with many other exploration and development companies throughout the world who have access to greater resources.

We operate in a highly competitive environment in which we compete with other exploration and development companies to acquire a limited number of prospective oil and gas properties. Many of our competitors are much larger than we are and, as a result, may enjoy a competitive advantage in accessing financial, technical and human resources. They may be able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical and human resources permit.

Our share ownership is highly concentrated and, as a result, our principal shareholder effectively controls our business.

Our largest shareholder, Robert M. Friedland, owns approximately 29% of our common stock and effectively controls our Board of Directors and determines our policies, business and affairs and the outcome of any corporate transaction or other matter, including mergers, consolidations and the sale of all or substantially all of our assets.

In addition, the concentration of our ownership may have the effect of delaying, deterring or preventing a change in control that otherwise could result in a premium in the price of our common stock.

If we lose our key management and technical personnel, our business may suffer.

We rely upon a relatively small group of key management and technical personnel. Messrs. David Martin, E. Leon Daniel and John Carver, in particular, have extensive experience in oil and gas operations throughout the world. We do not maintain any key man insurance. We do not have employment agreements with certain of our key management and technical personnel and we cannot assure you that these individuals will remain with us in the future. An unexpected partial or total loss of their services would harm our business.

COMPETITION

The oil and gas industry is highly competitive. Our position in the oil and gas industry, which includes the search for and development of new sources of supply, is particularly competitive. Our competitors include major, intermediate and junior oil and natural gas companies and other individual producers and operators, many of which have substantially greater financial and human resources and more developed and extensive infrastructure than we do. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets than we can and may enjoy a competitive advantage in the recruitment of qualified personnel. They may be able to absorb the burden of any changes in laws and regulations in the jurisdictions in which we do business more easily than we can, adversely affecting our competitive position. Our competitors may be able to pay more for productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, to evaluate and select suitable properties, implement advanced technologies, and to consummate transactions in a highly competitive environment. The oil and gas industry also competes with other industries in supplying energy, fuel and other needs of consumers. See "Risk Factors".

ENVIRONMENTAL REGULATIONS

Both our oil and gas and GTL operations are subject to various levels of government laws and regulations relating to the protection of the environment in the countries in which they operate. See "Risk Factors". We believe that our operations comply in all material respects with applicable environmental laws.

In the U.S., environmental laws and regulations, implemented principally by the Environmental Protection Agency, Department of Transportation and the Department of the Interior and comparable state agencies, govern the management of hazardous waste, the

discharge of pollutants into the air and into surface and underground waters and the construction of new discharge sources, the manufacture, sale and disposal of chemical substances, and surface and underground mining. These laws and regulations generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

In China, environmental regulation does not exist on a national level. Individual projects are monitored by the state and the standard of environmental regulation depends on each case.

GOVERNMENT REGULATIONS

Our business is subject to certain U.S. and Chinese federal, state and local laws and regulations relating to the exploration for, and development, production and marketing of, crude oil and natural gas, as well as environmental and safety matters. In addition, the Chinese government regulates various aspects of foreign company operations in China. Such laws and regulations have generally become more stringent in recent years in the U.S., often imposing greater liability on a larger number of potentially responsible parties. It is not unreasonable to expect that the same trend will be encountered in China. Because the requirements imposed by such laws and regulations are frequently changed, we are not able to predict the ultimate cost of compliance.

EMPLOYEES

At December 31, 2003 we had 103 employees. None of our employees are unionized.

RESERVES, PRODUCTION AND RELATED INFORMATION

See the "Supplementary Disclosures About Oil and Gas Production Activities" which follows the notes to our financial statements set forth in Item 8 in this Annual Report for information with respect to our oil and gas producing activities. We have not filed with or included in reports to any other U.S. federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

The following tables set forth, for each of the last three fiscal years, our average sales prices and average operating costs per unit of production. Average operating costs include lifting costs and production taxes, but exclude allocated head office engineering support costs, depreciation, depletion and amortization, royalties, income taxes, interest, selling and administrative expenses.

	Average Sales Price			Average Operating Costs		
	2003	2002	2001	2003	2002	2001
Crude Oil and Natural Gas ($/Boe)						
U.S.	$25.69	$22.43	$21.93	$7.65	$6.76	$ 7.28
China	$28.41	$22.30	$24.42	$9.31	$6.49	$10.50

The following tables set forth the number of commercially productive wells (both producing wells and wells capable of production) in which we held a working interest at the end of each of the last three fiscal years:

	2003		2002		2001	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S.	77	60.4	60(3)	43.9(3)	59	48.4
China	9	7.4	9(4)	7.4(4)	13	10.8

(1) Gross wells are the total number of wells in which an interest is owned.
(2) Net wells are the sum of fractional interests owned in gross wells.
(3) After the sale of 4.4 net (7 gross) Spraberry wells in August 2002 and a 50% working interest, or 6.9 net wells, in our remaining Spraberry wells in October 2002.
(4) After the sale of 3.4 net (4 gross) Daqing wells in January 2002.

The following table sets forth, for each of the last three fiscal years, our participation in the completed drilling of net crude oil and natural gas wells:

Exploratory

	Productive 2003	2002	2001
U.S.	—	—	—
China	—	—	—
Total	0	0	0

	Dry 2003	2002	2001
U.S.	—	1.7(1)	1.5
China	—	—	—
Total	0	1.7	1.5

(1) Includes 1.5 (3 gross) net exploratory wells drilled in Kentucky during 2001, which were determined to be dry in 2002.

At the end of 2003, 2002 and 2001 we had 2.8 (5 gross), 2.3 (5 gross) and 3.3 (7 gross) net exploratory wells, respectively, which were either in the process of drilling or suspended.

Development

	Productive 2003	2002	2001
U.S.	17.0	8.8	22.8
China	—	—	—
Total	17.0	8.8	22.8

	Dry 2003	2002	2001
U.S.	2.0	-	-
China	—	—	—
Total	2.0	0	0

In the last quarter of 2003, we set surface casing for 6 development wells in China, of which the first of these wells was completed in January 2004.

The following tables set forth our holdings of developed and undeveloped oil and gas acreage as at December 31, 2003:

	Developed		Undeveloped	
	Gross Acres(1)	Net Acres(2)	Gross Acres(1)	Net Acres(2)
U.S.	12,420	5,230	126,519	40,608
China(3)	1,729	1,418	900,320	896,607

(1) Gross acres include the interests of others.
(2) Net acres exclude the interests of others.
(3) The number of developed acres disclosed in respect of our China project relates only to those portions of the field covered by our producing operations and does not include the remaining portions of the field previously developed by CNPC.

The following table sets out estimates of our share of proved reserves in respect of our U.S. and China operations and calculations of cash flows, before tax and after tax, undiscounted and discounted at 10% and 15%, based on costs and prices as at December 31, 2003. Estimates for our U.S. and China operations were prepared by independent petroleum consultants Netherland, Sewell & Associates Inc. and Gilbert Laustsen Jung Associates Ltd., respectively.

	Our Share		Our Share of Before Tax Cash Flows in thousands of dollars discounted at:			Our Share of After Tax Cash Flows in thousands of dollars discounted at:		
	OIL (MBbl)	GAS (MMcf)	0%	10%	15%	0%	10%	15%
Net Proved Reserves(1)								
U.S.	1,563	695	$24,576	$17,110	$15,106	$24,576	$17,110	$15,106
China	15,699	—	232,591	114,690	82,019	170,944	81,764	59,142
	17,262	695	$257,167	$131,800	$97,125	$195,520	$98,874	$74,248

(1) "Net Proved Reserves" are our share of the estimated quantities of crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions. See the "Supplementary Disclosures about Oil and Gas Production Activities", which follow the notes to our financial statements set forth in Item 8 of this Annual Report.

Ivanhoe is a United States Securities and Exchange Commission ("SEC") registrant and files annual reports on Form 10-K. Accordingly, our reserves estimates and securities regulatory disclosures are prepared based on U.S. disclosure standards. In 2003, certain Canadian securities regulatory authorities adopted *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") which prescribes certain standards that Canadian companies are required to follow in the preparation and

disclosure of reserves and related information. We applied for, and have been granted, exemptions from certain NI 51-101 disclosure requirements. These exemptions permit us to substitute disclosures based on U.S. standards for much of the annual disclosure required by NI 51-101 and to prepare our reserves estimates and related disclosures in accordance with U.S. disclosure requirements, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") modified to reflect U.S. disclosure requirements.

The reserves quantities disclosed in this Annual Report on Form 10-K represent net proved reserves calculated on a constant price basis using the standards contained in SEC Regulation S-X and FAS 69. Such information differs from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The primary differences between the U.S. requirements and the NI 51-101 requirements are as follows:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the U.S. whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of proved reserves calculated using year-end constant prices and costs only whereas NI 51-101 also requires disclosure of reserves and related future net revenues using forecast prices;
- the SEC mandates disclosure of proved and proved producing reserves by country only whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC does not require separate disclosure of proved undeveloped reserves or related future development costs whereas NI 51-101 requires disclosure of more information regarding proved undeveloped reserves, related development plans and future development costs; and
- the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's board of directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports.

The foregoing is a general and non-exhaustive description of the principal differences between U.S. disclosure standards and NI 51-101 requirements.

ITEM 3. LEGAL PROCEEDINGS

We are not currently a party to any material legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matter was submitted to a vote of security holders during the fourth quarter of 2003.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information

Our common shares traded on the NASDAQ National Market and SmallCap Market during 2002 and 2003. As a result of our shares closing below $1.00 per share for 30 consecutive trading days during 2002 our shares were transferred from the NASDAQ National Market to the NASDAQ SmallCap Market on December 27, 2002. Currently our shares are traded on the NASDAQ SmallCap Market and The Toronto Stock Exchange.

The high and low sale prices of our common shares as reported on the NASDAQ and the Toronto Stock Exchange for each quarter during the past two years are as follows:

NASDAQ MARKET (IVAN)
(US$)

	2003				2002			
	4th Q	3rd Q	2nd Q	1st Q	4th Q	3rd Q	2nd Q	1st Q
High	7.55	3.07	1.18	.60	.65	1.07	2.02	2.23
Low	2.52	.79	.42	.50	.53	.85	1.72	1.93

THE TORONTO STOCK EXCHANGE (IE)
(CDN$)

	2003				2002			
	4th Q	3rd Q	2nd Q	1st Q	4th Q	3rd Q	2nd Q	1st Q
High	10.40	4.15	1.60	.88	1.01	1.74	3.12	3.50
Low	3.30	1.10	.53	.77	.88	1.45	2.83	3.11

On December 31, 2003, the closing prices for our common shares were $3.74 on the NASDAQ SmallCap Market and Cdn. $4.85 on The Toronto Stock Exchange.

Exemptions from Certain NASDAQ Corporate Governance Rules

NASDAQ rules provide that NASDAQ may provide exemptions from the NASDAQ corporate governance standards to a foreign issuer when those standards are contrary to a law, rule or regulation of any public authority exercising jurisdiction over such issuer or contrary to generally accepted business practices in the issuer's country of domicile. We have applied to the NASDAQ for, and expect to receive, exemptions from certain NASDAQ corporate governance standards that are contrary to the laws, rules, regulations or generally accepted business practices of Canada. These exemptions and the practices followed by us are described below:

- We are seeking and expect to receive an exemption from NASDAQ's requirement that a majority of the Board of Directors of a corporation must be comprised of independent directors. The existing Toronto Stock Exchange guidelines recommend but do not require that a majority of the directors of a corporation be "unrelated" directors. An "unrelated" director is a director who is independent of management and is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the corporation, other than interests and relationships arising from shareholding. Three of the eight directors on our board are "unrelated" for the purposes of the Toronto Stock Exchange guidelines.

Holders of Common Shares

As at December 31, 2003, a total of 161,359,339 of our common shares were issued and outstanding and held by 135 holders of record with an estimated 47,600 additional stockholders whose shares were held for them in street name or nominee accounts.

Dividends

We have not paid any dividends on our outstanding common shares since we were incorporated and we do not anticipate that we will do so in the foreseeable future. The declaration of dividends on our common shares is, subject to certain statutory restrictions described below, within the discretion of our Board of Directors based on their assessment of, among other factors, our earnings or lack thereof, our capital and operating expenditure requirements and our overall financial condition. Under the *Yukon Business Corporations Act*, our Board of Directors has no discretion to declare or pay a dividend on our common shares if they have reasonable grounds for believing that we are, or after payment of the dividend would be, unable to pay our liabilities as they become due or that the realizable value of our assets would, as a result of the dividend, be less than the aggregate sum of our liabilities and the stated capital of our common shares.

Exchange Controls and Taxation

There is no law or governmental decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to a non-resident holder of our common shares, other than withholding tax requirements.

There is no limitation imposed by the laws of Canada, the laws of the Yukon, or our constating documents on the right of a non-resident to hold or vote our common shares, other than as provided in the *Investment Canada Act* (Canada) (the "Investment Act"), which generally prohibits a reviewable investment by an entity that is not a "Canadian", as defined, unless after review, the minister responsible for the Investment Act is satisfied that the investment is likely to be of net benefit to Canada. An investment in our common shares by a non-Canadian who is not a "WTO investor" (which includes governments of, or individuals who are nationals of, member states of the World Trade Organization and corporations and other entities which are controlled by them), at a time when we were not already controlled by a WTO investor, would be reviewable under the Investment Act under two circumstances. First, if it was an investment to acquire control (within the meaning of the Investment Act) and the value of our assets, as determined under Investment Act regulations, was Cdn. $5 million or more. Second, the investment would also be reviewable if an order for review was made by the federal cabinet of the Canadian government on the grounds that the investment related to Canada's cultural heritage or national identity (as prescribed under the Investment Act), regardless of asset value. An investment in our common shares by a WTO investor, or by a non-Canadian at a time when we were already controlled by a WTO investor, would be reviewable under the Investment Act if it was an investment to acquire control and the value of our assets, as determined under Investment Act regulations, was not less than a specified amount, which for 2004 is Cdn.$237 million. The Investment Act provides detailed rules to determine if there has been an acquisition of control. For example, a non-Canadian would acquire control of us for the purposes of the Investment Act if the non-Canadian acquired a majority of our outstanding common shares. The acquisition of less than a majority, but one-third or more, of our common shares would be presumed to be an acquisition of control of us unless it could be established that, on the acquisition, we were not controlled in fact by the acquirer. An acquisition of control for the purposes of the Investment Act could also occur as a result of the acquisition by a non-Canadian of all or substantially all of our assets.

Amounts that we may, in the future, pay or credit, or be deemed to have paid or credited, to you as dividends in respect of the common shares you hold at a time when you are not a resident of Canada within the meaning of the *Income Tax Act* (Canada) will generally be subject to Canadian non-resident withholding tax of 25% of the amount paid or credited, which may be reduced under the Canada-U.S. Income Tax Convention (1980) (the "Convention"). Currently, under the Convention, the rate of Canadian non-resident withholding tax on the gross amount of dividends paid or credited to a U.S. resident is generally 15%. However, if the beneficial owner of such dividends is a U.S. resident corporation, which owns 10% or more of our voting stock, the withholding rate is reduced to 5%. In the case of certain tax-exempt entities, which are residents of the U.S. for the purpose of the Convention, the withholding tax on dividends may be reduced to 0%.

Sales of Unregistered Securities

During the year ended December 31, 2003, we issued securities which were not registered under the Securities Act of 1933 (the "Act") as follows:

- in April 2003, we issued 75,000 common shares to an accredited investor for corporate finance advisory services in a transaction exempt from registration under Section 4(2) of the Act;
- in June 2003, we issued 2,000,000 common shares at a price of $0.50 per share to a Hong Kong company pursuant to the conversion of a previously issued $1,000,000 convertible debenture in a transaction exempt from registration under Rule 903 of the Act;
- in July 2003, we issued 3,000,000 special warrants at a price of $1.00 per special warrant to a Bahamian institutional investor in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercisable to acquire, for no additional consideration one common share and one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in July 2003;
- in August 2003, we issued 3,000,000 special warrants at a price of $1.00 per special warrant and 3,529,412 special warrants at a price of $1.70 per special warrant to a Bahamian institutional investor in two transactions exempt from registration under Rule 903 of the Act. Each special warrant was exercisable to acquire, for no additional consideration one common share and one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in September 2003;
- in October 2003, we issued 3,125,000 special warrants at a price of $4.00 per special warrant to a Bahamian institutional investor in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercisable to acquire, for no additional consideration one common share and four-tenths of one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in November 2003; and
- in November 2003, we issued 250,000 common shares at a price of $1.70 to a Bahamian institutional investor pursuant to the exercise of previously issued share purchase warrants in a transaction exempt from registration under Rule 903 of the Act.

ITEM 6. FIVE YEAR SUMMARY OF SELECTED FINANCIAL DATA

The selected financial data set forth below are derived from the accompanying financial statements, which form part of this Annual Report. The financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") applicable in Canada, which are not materially different from GAAP in the U.S. except as noted immediately below in "Reconciliation to U.S. GAAP". See also Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations".

The following table shows selected financial information for the years indicated:

	Year ended December 31,				
	2003	2002	2001	2000	1999
	(stated in thousands of U.S. dollars, except per share amounts)				
Financial Position					
Total assets	106,574	107,088	104,003	99,800	47,659
Long-term debt	833	Nil	Nil	Nil	Nil
Shareholders' equity	100,537	100,548	96,897	95,838	41,692
Results of Operations					
Revenues	9,659	8,437	9,722	14,063(2)	6,210
Net income (loss)	(29,703)(4)	(6,819)(4)	(21,122)(4)	5,429	(7,802)(1)
Net incomes (loss) per share — basic	(0.20)	(0.05)	(0.16)	0.05	(0.08)
Net income (loss) per share — diluted	(0.20)	(0.05)	(0.16)	0.04	(0.08)
Cash Flow					
Cash provided (used) by operating activities	(2,059)	(2,758)	2,433	(11,833)	(6,230)
Capital expenditures	(15,391)	(18,828)	(40,504)	(40,827)	(10,728)
Cash provided (used) by all other investing activities, net	(537)	5,286	(155)	32,002(3)	5,158
Cash provided by financing activities, net	28,498	10,583	18,229	47,715	735

(1) Includes asset write-down of $2.5 million. See Note 8 to our financial statements under Item 8 in our 2001 Annual Report.
(2) Includes $12.2 million gain on sale of our Russian project. See Note 9 to our financial statements under Item 8 in our 2001 Annual Report.

(3) Includes $28.2 million in proceeds from the sale of our Russian project. See Note 9 to our financial statements under Item 8 in our 2001 Annual Report.
(4) Includes asset write-downs of $23.3 million, $2.4 million and $14.0 million for 2003, 2002 and 2001, respectively. See Notes 4 and 13 to our financial statements under Item 8 in this Annual Report.

Reconciliation to U.S. GAAP

Our financial statements have been prepared in accordance with GAAP applicable in Canada, which differ in certain respects from those principles that we would have followed had our financial statements been prepared in accordance with GAAP in the U.S. The only material differences between Canadian and U.S. GAAP, which affect our financial statements, is that an increase in ascribed value of shares issued for royalty interests in 2000 and 1999 of $1.4 million, additional impairment provision of $10.0 million in 2001 for our China properties and net write-downs of $4.1 million from 2001 to 2003 in connection with development costs for our GTL prospects is required under U.S. GAAP. For the U.S. GAAP reconciliations, see Note 20 to our financial statements in this Annual Report and Notes 19 and 15 to our financial statements under Item 8 in our 2002 and 2001 Annual Reports, respectively.

Had we followed U.S. GAAP, certain selected financial information reported above, in accordance with Canadian GAAP, would have been reported as follows:

	Year ended December 31,				
	2003	2002	2001	2000	1999
	(stated in thousands of U.S. dollars, except per share amounts)				
Financial Position					
Total Assets	94,024	91,921	90,219	101,158	48,852
Shareholders' equity	87,987	85,279	83,113	97,196	42,885
Results of Operations					
Net earnings (loss)	(27,086)	(8,202)	(36,264)	5,429	(7,802)
Net earnings (loss) per share — basic	(0.18)	(0.06)	(0.28)	0.05	(0.09)
Net earnings (loss) per share — diluted	(0.18)	(0.06)	(0.28)	0.05	(0.09)
Cash Flow					
Cash used by operating activities	(2,851)	(4,656)	(1,456)	(11,833)	(6,230)
Capital expenditures	(14,599)	(16,932)	(36,615)	(40,827)	(10,728)

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Critical Accounting Principles and Estimates

Our accounting principles are described in Note 2 to Notes to the Consolidated Financial Statements in Item 8. We prepare our Consolidated Financial Statements in conformity with GAAP in Canada, which conform in all material respects to U.S. GAAP except for those items disclosed in Note 20 to Notes to the Consolidated Financial Statements. For U.S. readers we have detailed the differences and have also provided a reconciliation of the differences between U.S. and Canadian GAAP in Note 20 to Notes to the Consolidated Financial Statements.

The preparation of our financial statements requires us to make estimates and judgments that affect our reported amounts of assets, liabilities, revenue and expenses. On an ongoing basis we evaluate our estimates, including those related to asset impairment, revenue recognition, allowance for doubtful accounts and contingencies and litigation. These estimates are based on information that is currently available to us and on various other assumptions that we believe to be reasonable under the circumstances. Actual results could vary from those estimates under different assumptions and conditions.

We have identified the following critical accounting policies that affect the more significant judgments and estimates used in preparation of our consolidated financial statements.

Full Cost Accounting — We follow the full cost method of accounting for our oil and gas operations (as more fully described in Note 2 to the Consolidated Financial Statements), as compared to the other generally accepted method, successful efforts. Under the full cost method, costs associated with geological and geophysical activities and drilling successful and unsuccessful wells are capitalized on a country-by-country cost center basis. As a consequence, we may be more exposed to potential impairments if the carrying value of our evaluated oil and gas assets exceeds their future expected cash flows. This may occur if recoverable reserve estimates decrease, commodity prices decline or future estimates for capital, operating and income taxes increase, to levels that would significantly affect anticipated future cash flows.

Oil and Gas Reserves — The process of estimating quantities of proved reserves is inherently uncertain and the reserve estimates included in this document are only estimates (see "Risk Factors"). You should not assume that the present value of our future cash flows is the current market value of our estimated proved oil and gas reserves. In accordance with GAAP, we base the estimated future net cash flows from proved reserves on prices and costs on the date of estimate. Actual future prices and costs may be materially

higher or lower than the prices and costs at the date of estimate.

Depletion — Our rate of recording depletion is dependent upon our estimate of proved reserves and our assessment of unevaluated properties. If the estimates of proved reserves decline or the carrying value of our evaluated oil and gas assets increases as a result of our assessment of our unevaluated properties, the rate at which we record our depletion expense increases, reducing net income. A decline in proved reserves may occur from lower product prices, which may make it uneconomic to drill for and produce higher cost fields.

Impact of New and Pending Canadian GAAP Accounting Standards

In December 2001, the Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, "Hedging Relationships" (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied. The guideline is effective for fiscal years beginning on or after July 1, 2003. Adoption of AcG-13 is not expected to have a material impact on our financial position or results of operations as we are already in compliance with Financial Accounting Standards Board (FASB) Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities".

In September 2002, the CICA approved Section 3063, "Impairment of Long Lived Assets" (S.3063). S.3063 establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets, and applies to long-lived assets held for use. An impairment loss is recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. S.3063 is effective for fiscal years beginning on or after April 1, 2003. Adoption of S.3063 is not expected to have a material impact on our financial position or results of operations.

In December 2002, the CICA approved Section 3110, "Asset Retirement Obligations" (S.3110). S.3110 requires liability recognition for retirement obligations associated with property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liabilities. This fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful life. The liabilities accrete until expected settlement of the retirement obligations. S.3110 is effective for fiscal years beginning on or after January 1, 2004. We elected early implementation of this accounting policy. Accordingly, effective January 1, 2003, the Company changed its accounting policy to capitalize asset retirement costs as part of the carrying value of its oil and gas properties and adjusted the amount of its site restoration liability to the present value of the liability for the corresponding asset retirement obligation as of this date. The Company has adopted the policy without retroactive adjustment of prior years because implementation of this change had an immaterial effect on the Company's financial position and results of operations in prior years and in the current period.

In September 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting - Full Cost" (AcG 16). AcG 16 is to be applied no later than January 1, 2004 and provides a new methodology for determining impairment of oil and gas assets, provides linkage to the new standards for determination of reserves and related disclosures under National Instrument 51-101 and revises certain other aspects of accounting for oil and gas operations under the full cost method. Adoption of AcG 16 is not expected to have a material impact on our financial position or results of operations.

The following standards issued by the CICA do not impact us:

- Accounting Guideline 14, "Disclosure of Guarantees", effective for interim and annual periods beginning on or after January 1, 2003.
- Amendment to Section 3860, "Financial Instruments Disclosure and Presentation", effective for fiscal years beginning on or after November 1, 2004.
- Section 1100, "General Accounting Principles", effective for years beginning on or after October 31, 2003.
- Section 1400, "General Standards of Financial Statement Presentation", effective for years beginning on or after October 31, 2003.
- Accounting Guideline 15, "Consolidation of Variable Interest Entities", effective for annual and interim periods beginning on or after January 1, 2004.

Results of Operations and Overview

Despite our disappointment with the termination of our negotiations for a GTL development and production contract in Qatar, there were some promising developments for Ivanhoe in the last half of 2003 and we are excited about these opportunities going forward. Having received approval of the Dagang ODP earlier in 2003, we commenced drilling our first development wells in December 2003 and completed our first well in January 2004. In November 2003, we signed a heads of agreement with CITIC to jointly develop the Dagang field which calls for the drilling of up to 115 new oil wells and 28 re-completions over a three year period. We see significant potential from our new EOR projects. We plan to use our thermal recovery and horizontal well expertise to develop the LAK Ranch field in the Powder River Basin, Wyoming. Our acquisition of an equity stake in Ensyn and exclusive rights to use the Ensyn RTP™ Process in specific countries in the Far East, Mid East and South America offers us excellent potential for commercializing heavy-oil

fields in those regions. Although we have no signed agreements and all of our work and preparation at this time is at the initial stages, we plan to leverage the experience of our senior management in Iraq to help expedite the development activities needed to increase oil production from existing fields. We continue to pursue GTL projects in Qatar, Egypt and Bolivia and the removal of territorial restrictions from our Syntroleum master license has opened GTL opportunities in China and other countries under our worldwide strategic alliance with CITIC. We completed reprocessing of existing seismic in the Zitong natural gas field in the Sichuan Basin and have started the acquisition of just over 1,000 kilometers of new 2-D seismic data in preparation for drilling the first exploration well in the last half 2004.

Although production from our South Midway field increased 24% in 2003, total U.S. production was down 6% as a result of the partial sale of reserves in the Spraberry field in 2002. Production for 2003 in China was flat compared to 2002. Our revenues, however, increased 15% for 2003 due to a 20% increase in oil and natural gas prices. See "Production and Operations" below for more details.

Our net loss for 2003 was $29.7 million ($0.20 per share) compared to net losses in 2002 and 2001 of $6.8 million ($0.05 per share) and $21.1 million ($0.16 per share), respectively. The increase in our net loss from 2002 to 2003 of $22.9 million is due mainly to a $20.0 million impairment of our U.S. oil and gas assets, $0.9 million increase in write-downs of our GTL investments from year-to-year and a $2.2 million increase in project identification and general and administrative costs. See "General and Administration" below. This is partially offset by an increase in net revenues of $0.7 million from 2002 to 2003. See "Production and Operations" below. The $20.0 million impairment for 2003 is due mainly to an increase in the carrying costs of our evaluated U.S. oil and gas assets primarily in Northwest Lost Hills, East Texas and North South Forty when compared to the estimated recoverable value of our U.S. proved reserves at year end 2003. Such carrying costs increased as a result of our decision, in the fourth quarter of 2003, to potentially farm-out up to 50% of our working interest to one or more partners to fund a test of Northwest Lost Hills # 1-22. During 2003, we completed our evaluation of significant portions of our acreage positions in East Texas and North South Forty and either relinquished or plan to relinquish our interests, thus adding to the carrying value of our evaluated U.S. oil and gas assets.

The decrease in our net loss from 2001 to 2002 of $14.3 million is due mainly to an $11.6 million decrease in write down of our properties from year-to-year and a $3.2 million reduction in project identification and general and administrative costs. We wrote-down $3.3 million of our GTL investments in 2003 as a result of the termination of our contract negotiation for a GTL development and production contract in Qatar and we wrote-down $2.4 million in 2002 related to our investment in Syntroleum's Sweetwater GTL project. In 2001, we wrote-down our U.S. oil and gas properties by $14.0 million due to an impairment of our carrying costs as a result of a decline in oil and natural gas prices in the fourth quarter.

Our net cash and cash equivalents increased by $10.5 million in 2003 compared to decreases in 2002 and 2001 of $5.7 million and $20.0 million, respectively. We raised $17.9 million more in 2003 than in 2002 through private placements and the exercise of warrants and incentive stock options and we invested $3.4 million less in 2003 than in 2002 on exploration, development and GTL activities. See "Exploration and Development Activities" and "GTL Activities" below. This is partially offset by a reduction in cash generated from asset sales as we sold non-core assets in China and Texas for $5.4 million in 2002. The decrease in our cash deficiency from 2001 to 2002 of $14.3 million is due mainly to a $21.7 million reduction in our spending on exploration, development and GTL activities in 2002 and $5.4 million from the sale of non-core assets. This is partially offset by an $8.1 million reduction in cash from private placements and the exercise of warrants and incentive stock options and a decrease in cash from operations of $5.2 million primarily as a result of higher usage of working capital in 2002.

Production and Operations

Oil and gas revenues were $9.6 million in 2003 compared to revenues of $8.3 million and $9.1 million in 2002 and 2001, respectively. Production volumes in 2003 declined 4% from 2002 and declined 7% from 2001 to 2002 due mainly to the sale of our interests in certain wells in the Spraberry field in the last half of 2002 and our working interest in the Daqing field in January 2002. The decline in production volumes in 2003 were more than offset by a 20% increase in oil and natural gas prices from 2002 particularly in China where oil prices increased 22%. Oil and natural gas prices for the U.S. and China combined were down slightly from 2001 to 2002.

At our South Midway field we have drilled 58 wells, 51 of which are producing wells. We are currently producing approximately 460 net Bopd compared to 490 and 400 net Bopd at the end of 2002 and 2001, respectively. We initiated our full-scale cyclic steam enhancement program in May 2002 in the primary area of South Midway, increasing initial production rates ranging from 2.5 to 4 times. Two wells were drilled in the southern expansion of South Midway in 2002 and responded very well to cyclic steaming with initial production rates of approximately 50 net Bopd. In 2003, we drilled 15 new wells in the southern expansion of South Midway. We started cyclic steaming the new southern expansion wells in the fourth quarter of 2003 and the wells continue to respond to heat injection. The project is still early in its life and as a result we did not realize, at year-end 2003, the increase in proved reserves we had anticipated at mid-year 2003. The reservoir is responding efficiently to steam injection. With larger steam injection cycles, production is expected to peak by mid-year 2005 and the project should realize the anticipated increase in proved reserves. To date, we have cycle steamed all of the southern expansion wells with two cycles and eight wells with a third cycle.

At year-end 2003, we were producing from seven pilot phase wells in the Dagang field at the rate of 393 net Bopd compared to 467 net Bopd and 432 net Bopd at the end of 2002 and 2001, respectively. The decrease in production rates for 2003 is mainly due to workovers, natural declines and the suspension of one pilot phase well pending conversion to water injection service. The production decreases in Dagang were offset by an increase in production from the royalty interest we retained in the Daqing project, which we sold in 2002.

Operating costs, including production taxes and engineering support, were $4.3 million for 2003 or $12.03 per Boe, compared to $3.8 million, or $10.33 per Boe, in 2002 and $4.8 million, or $11.95 per Boe in 2001. On our U.S. properties, the $0.89 per Boe increase in operating costs, excluding production taxes and engineering support, in 2003 from 2002 is due mainly to the increased usage of purchased natural gas for steam generation in the southern expansion of South Midway. The increase in costs for steam generation of $2.36 per Boe is partially offset in 2003 by a $1.47 per Boe reduction in costs at the Spraberry field as the wells mature. In 2002, the increase in costs for steam generation of $0.66 per Boe compared to 2001 is more than offset by a $1.18 per Boe decrease in primary operating costs as a result of the installation of permanent production and electrical facilities in 2001 at South Midway. The $2.82 per Boe increase in operating costs, excluding production taxes and engineering support, at the Dagang field in 2003 from 2002 is mainly due to increased well workover costs and increased manpower costs in preparation for the full field development. Our operating costs decreased $4.01 per Boe in 2002 from 2001 at our Dagang field as a result of the installation of permanent electrical facilities on certain wells and an improvement in operating efficiencies.

Depletion costs were $3.7 million for 2003, or $10.44 per Boe, compared to $3.1 million, or $8.35, per Boe, in 2002 and $3.0 million, or $7.56 per Boe, in 2001. U.S. depletion costs per Boe in 2003 increased 26% primarily as a result of an increase in the carrying costs of our evaluated U.S. oil and gas assets primarily in Northwest Lost Hills, East Texas and North South Forty. U.S. depletion costs per Boe for 2002 increased 3% from 2001 primarily due to the reduction in our reserves as a result of the partial sale of our interests in Spraberry in 2002 and an increase in the carrying costs of our evaluated U.S. oil and gas assets. This increase is partially offset by a $14.0 million write-down of depletable costs in 2001. China depletion costs for 2003 increased 23% from 2002. A downward revision of our share of proved reserves at Dagang as a result of increased oil prices in 2003 increased our depletion rate $1.09 per Boe and $0.84 per Boe as a result of anticipated increases in Dagang future development costs. China depletion costs for 2002 increased 22% from 2001 primarily as a result of anticipated increases in Dagang future development costs resulting in an increase of $0.41 per boe and the sale of our reserves at Daqing, which increased our depletion rate $1.10 per boe.

Production and operating information for 2001 to 2003 are detailed below:

	2003			2002			2001		
	U.S.	China	Total	U.S.	China	Total	U.S.	China	Total
Net Production									
Boe	212,820	144.422	357,242	227,301	144,848	372,149	232,584	165,599	398,183
Boe/day for the year	583	396	979	623	397	1,020	637	454	1,091
Per Boe									
Oil and gas revenue	$ 25.69	$ 28.41	$ 26.79	$ 22.43	$ 22.30	$ 22.38	$ 21.93	$ 24.42	$ 22.96
Operating costs	7.65	9.31	8.52	6.76	6.49	6.66	7.28	10.50	8.62
Production taxes	1.03	-	0.62	1.21	-	0.74	1.01	-	0.59
Engineering Support	2.19	4.40	2.89	2.38	3.80	2.93	2.12	3.62	2.74
	10.87	13.71	12.03	10.35	10.29	10.33	10.41	14.12	11.95
Net revenue before depletion	14.82	14.70	14.76	12.08	12.01	12.05	11.52	10.30	11.01
Depletion	10.58	10.23	10.44	8.39	8.30	8.35	8.12	6.79	7.56
Net revenue from operations	$ 4.24	$ 4.47	$ 4.32	$ 3.69	$ 3.71	$ 3.70	$ 3.40	$ 3.51	$ 3.45

General and Administration

We continue to follow the practice of expensing the costs we incur in pursuing and investigating new projects, as well as costs associated with investment banking advice. In 2003, we incurred $7.9 million of general and administrative and project identification costs compared to $5.7 million and $8.8 million in 2002 and 2001, respectively. For 2003, $1.0 million of the increase from 2002 is a result of a decrease in such costs being allocated to our exploration, development and GTL activities due to a reduction in capital spending activity during 2003. The balance of the increase for 2003 is associated with fees incurred for the filing of a $100 million Canadian base shelf prospectus and corresponding U.S. shelf registration statement, exploring the possibility of securing a public listing for Sunwing and pursuing new sources of project financing as well as an increase in insurance costs for 2003. The decrease for 2002 is directly attributable to our reduction in activities related to finding and investigating new projects, including $1.4 million of investment banking services incurred in 2001. In addition, in the third quarter of 2002, we implemented a cost reduction program that continued into 2003.

Interest Income

Interest income represents income we earn on our excess cash balances during the year. The $0.5 million reduction in interest income

from 2001 to 2002 is due to decreased cash balances and a decline in interest rate yields.

Income Taxes

We have significant tax losses available to carry forward and reduce taxes otherwise payable. Details of these losses are in Note 14 to the consolidated financial statements included herein under Item 8. Given the uncertainty as to the utilization of these tax loss carry-forwards, we have followed the practice of recording a provision against the tax benefit asset resulting from these losses.

Exploration and Development Activities

Expenditures in 2003 on exploration and development activities were $14.6 million down from $16.9 million and $36.6 million in 2002 and 2001, respectively. Capital spending in the U.S. was $8.4 million in 2003 down $4.9 million compared to 2002. Completion of our drilling of the Northwest Lost Hills # 1-22 well and our drilling program in the Spraberry field in 2002 resulted in a $9.2 million decrease in 2003. This is partially offset by the drilling of our first wells at the Citrus and Sledge Hamar fields in December 2003 and for the drilling of new producing wells at South Midway and the construction of production facilities in the southern expansion of South Midway. For 2002, capital spending in the U.S. was $13.3 million down $16.7 million compared to 2001, primarily due to a reduction in development drilling in Spraberry and South Midway, the completion of our Magic Mountain and Kentucky drilling programs in 2001, and the completion of our significant acreage acquisition program in the Bossier Trend at year-end 2001. These decreases were partially offset by a $2.4 million increase in drilling costs on Northwest Lost Hills #1-22 in 2002.

Capital spending in China was $6.2 million, an increase of $2.6 million compared to 2002. This increase is mainly due to the start up of drilling under the Dagang development program at a cost of $2.1 million and $0.5 million for the reprocessing of 2-D seismic on the Zitong block. For 2002, capital spending in China was $3.6 million down $2.9 million compared to 2001, primarily as a result of the completion of our pilot test program in our Dagang project in February 2001 and the sale of our Daqing project in 2002, partially offset by a $0.5 million increase in spending on the Sichuan project in 2002.

At South Midway, we drilled 19 development and appraisal wells in 2003. Sixteen of these wells were commercial oil producers. This compares to 7 and 10 commercial oil wells we drilled in 2002 and 2001, respectively. After initiating a pilot cyclic steam project in 2001, we commenced a full-scale steam project in 2002 to enhance production. Facilities were expanded in 2003 to gather, test and cycle-steam the new production. Additionally, a steam generator was purchased and installed in 2003 to accelerate the thermal stimulation of producing wells and reduce the cost of leasing a steam generator. We are currently evaluating the wells drilled in the southern expansion before we drill additional wells in the second phase.

In Texas, we drilled 2 and 14 commercial wells in the Spraberry field in 2002 and 2001, respectively and in 2002 completed three wells drilled by Unocal under a farm-out agreement in the Creslenn Ranch and Lone Star prospects. Additionally, in 2001 we increased our acreage position in East Texas. In 2003, we spent minimal capital in Texas to maintain certain acreage positions and to farm-out our interests in Creslenn Ranch, Lone Star and Catfish Creek prospects. In 2003, we farmed out our interests in the three wells drilled by Unocal to test the shallower zones in the wells. A successful gas recompletion was made in the first Creslenn Ranch well from the Pettit limestone and the other two wells are in various stages of completion or testing of target zones. We retain a 30% working interest in the Creslenn Ranch prospect after payout and a 25% working interest in the Lone Star and Catfish Creek prospects after payout. An 11,000 foot well to test the Rodessa and Pettit formations is planned in the second quarter of 2004 in the Catfish Creek prospect as required by the farm-out agreement.

The Northwest Lost Hills #1-22 well was spud in 2001 and successfully drilled to a measured depth of 21,000 feet and a liner set to 19,620 feet in August 2002. While drilling the well, we encountered several high-pressure intervals, which indicated the presence of natural gas. Northwest Lost Hills # 1-22 was temporarily abandoned in 2003 until we can identify one or more partners to share the costs of the testing program. Temporary abandonment is expected to permit reentering the well at a later date for testing. Until it is tested, the well's commercial potential, if any, cannot be determined.

In December 2003, we completed drilling operations on Citrus #1 and Sledge Hamar # 1-7. These are our first wells in these two prospect areas. Both wells are on production and the prospects are being evaluated for further development.

We received approval of our ODP for Dagang in April 2003. In the fourth quarter of 2003, we completed drilling of six surface holes and commenced drilling of our first development well in December 2003, with completion and testing operations occurring in January 2004. The well, Nan 105, initially tested at 330 gross Bopd of 35 degree API oil, with no water. Plans for 2004 are to drill 22 development wells, 17 of which are expected to be completed, build associated facilities and convert three existing wells to water injection service.

In 2003, we commenced initial work on the first phase of a three-year exploration program in our Zitong block by reprocessing 2,500 kilometers of existing 2-D seismic data and commenced preparations to acquire just over 1,000 kilometers of new 2-D seismic data

starting in January 2004. Following the seismic acquisition and interpretation, we plan to spud the first of two exploration wells in the last half of 2004, as required under the first phase of the Zitong Contract.

In 2002, we completed our feasibility study for the Yudong block within the Sichuan province, submitted the report to PetroChina and submitted a letter of intent to negotiate a contract and a work plan for Yudong. We currently await PetroChina's reply.

Total capital spending on oil and gas operations, excluding non-cash transactions, for 2001 to 2003 was as follows:

	2003	2002	2001
Capital Expenditures:			
U.S.	$ 8,386	$ 13,306	$ 30,047
China	6,213	3,626	6,568
	$ 14,599	$ 16,932	$ 36,615
Comprised of:			
Property acquisition	$ 650	$ 913	$ 4,788
Royalty rights	-	-	1,191
Seismic	95	30	1,348
Exploration	3,053	10,811	10,197
Development	10,801	5,178	19,091
	$ 14,599	$ 16,932	$ 36,615

GTL Activities

GTL expenditures were $0.8 million in 2003 down from $1.9 million and $3.9 million in 2002 and 2001, respectively. The decreases in 2003 and 2002 are mainly due to the completion, in 2002, of technical and commercial feasibility studies of the Syntroleum process in large-scale GTL facilities we initiated in 2001.

In May 2003, negotiations with Qatar Petroleum to construct and operate a GTL production facility terminated without reaching an agreement and we wrote down $3.3 million of our GTL investments for expenditures incurred in connection with these negotiations.

In July 2003, we signed an agreement with Repsol and Syntroleum for a study to build a 90,000-barrel-per-day GTL plant in Bolivia. The commercialization study is underway including an analysis of alternative plant sites, transportation logistics and project economics. Upon determination that the project is economically feasible and meets financing requirements, the three parties will enter into discussions regarding a joint-venture agreement prior to undertaking definitive engineering and design work.

In December 2003, proposals for alternative plant designs for a GTL fuels, specialty products and lubricants plant were prepared and presented to the government of Egypt and its agencies responsible for the development and monetization of its natural gas reserves. We await the approval of our scope of work for a commercial feasibility study and the finalization of a heads of agreement authorizing the commercial feasibility study and setting aside of sufficient natural gas reserves for a 45,000 barrels per day GTL plant. We are pursuing this project jointly with Syntroleum.

Liquidity and Capital Resources

Our capital expenditure budget for 2004 is $51.8 million. Fifty percent of this budget is for oil and gas development programs in the Dagang, South Midway and Citrus fields. Thirty five percent of the budget is for exploration programs in the U.S. and our exploration capital commitment in the Zitong field including the drilling of the first exploration well in 2004 following the completion of seismic acquisition and interpretation. The remaining 15% of our budget is primarily for the pursuit of EOR and GTL projects. The strategic alliance we initiated with CITIC Energy in 2002 and further solidified in 2003 is expected to be key to financing the development of Sunwing's exploration and development projects in China and possibly GTL and EOR projects that we may be successful in acquiring worldwide. In January 2004, Sunwing signed farm-out and joint operating agreements with Richfirst, a wholly-owned subsidiary of CITIC, to acquire a 40% working interest in the Dagang project following an up front payment of $20 million and approval by China's regulatory authorities, both of which are expected to occur in the first quarter 2004. This agreement gives Richfirst the option to exchange its working interest in Dagang for common shares of Ivanhoe or Sunwing.

During 2003, we raised $24.1 million, net of share issue costs, through the issuance of common shares in four private placements and $1.0 million through a bank loan. Our current cash position is expected to enable us to initiate our short-term objectives of exploration in East Texas, California and Zitong and our development programs in our Citrus and Dagang fields as well as further our EOR and GTL initiatives. We are also looking at acquisitions of proven and probable reserves as a means of supplementing our growth strategy. In October 2003, we filed a base shelf prospectus with Canadian securities regulatory authorities and a shelf registration statement with the U.S. Securities and Exchange Commission to qualify for potential future sale in Canada and the U.S. up to $100 million of various types of securities, including common shares, preferred shares, warrants and debt securities. These shelf filings are expected to give us greater flexibility to fund our expansion and capital programs and will allow us to take advantage of a broader

range of financing opportunities on a timelier basis. A combination of such equity financing, as well as convertible debenture, debt and mezzanine financing and joint venture partner participation, will be required to complete our future capital programs. We cannot assure you that we will be successful in raising the additional funds necessary or securing joint venture partners to complete our capital programs. If we are unsuccessful, we will have to prioritize our capital programs, which may result in delaying and potentially losing some valuable business opportunities.

Contractual Obligations

The table below summarizes and cross-references the contractual obligations that are reflected in our Consolidated Balance Sheets and/or disclosed in the accompanying Notes:

			Payments Due by Year			
	Total	2004	2005	2006	2007	After 2007
Purchase Agreements:	$ -	$ -	$ -	$ -	$ -	$ -
Consolidated Balance Sheets:						
Notes payable – current portion *(Note 5)*	167	167	-	-	-	-
Long term debt *(Note 5)*	833	-	333	333	167	-
Footnote Disclosure:						-
Operating leases *(Note 18)*	1,332	533	442	306	51	-
Exploration commitment (a) *(Note 17)*	16,600	7,300	9,300	-	-	-
Total	$ 18,932	$ 8,000	$ 10,075	$ 639	$ 218	$ -

(a) This represents our estimate of the remaining expenditure commitment for the minimum work program during the first phase of Zitong. This is a total spending commitment and not a commitment per year. The amounts per year are based on our current estimate.

Off Balance Sheet Arrangements

At December 31, 2003 and 2002, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Related Party Transactions

We have entered into agreements with a number of entities, some of which are related through common directors or shareholders, to share administrative personnel, aircraft, office space and facilities. The agreement for the usage of aircraft was terminated in 2003. We are billed on a cost recovery basis. The costs incurred in the normal course of business with respect to the above arrangements amounted to $0.9 million for 2003, $1.2 million for 2002 and $2.7 million for 2001. In addition, a company controlled by a director provides consulting services to Ivanhoe. Consulting services and out of pocket expenses paid to this company were $0.4 million for 2003 and 2002 and $0.7 million for 2001. At year-end, amounts included in accounts payable under these arrangements totaled $0.1 million in 2003, $0.8 million in 2002 and $1.1 million in 2001.

We borrowed $1.25 million from a related company controlled by a director of Ivanhoe. The loan, plus accrued interest, was repaid in September 2003.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We have exploration and development projects in the U.S. and China. Our projects are at various stages and, like all exploration companies in the oil and gas industry, we are exposed to the significant risk that our exploration activities will not necessarily result in a discovery of economically recoverable reserves.

We currently have limited production in the U.S and China, which have not generated sufficient cash from operations to fund our exploration and development activities. Historically, we have relied on the equity markets as the primary source of capital to fund our expansion and growth opportunities.

The Company's results of operations are sensitive mainly to fluctuations in oil and natural gas prices. We periodically engage in derivatives to hedge the cash flow from a portion of our U.S. oil production. See Note 12 to the Consolidated Financial Statements in Item 8.

We are exposed to the risk that we may require a provision for impairment as to the carrying value of our evaluated oil and gas assets.

Such value is compared quarterly to the estimated recoverable value of our proved reserves based on period-end commodity prices, unescalated. We impaired $20.0 million and $14.0 million of our oil and gas assets in 2003 and 2001, respectively. As at December 31, 2003, we have $31.2 million of oil and gas assets, which have not yet been evaluated including $15.5 million in our Northwest Lost Hills prospect. If we are unable to identify partners to share the costs to test the Northwest Lost Hills # 1-22 well in 2004, or if the well is tested but determined to be uneconomic, we may be required to further impair the carrying value of our oil and gas assets.

We are exposed to the risk that we will be unable to engage competent cost-effective contractors and suppliers for our operations, risks that damage to, or malfunction of, our equipment will hinder our ability to carry out our exploration activities and risks that foreign laws may not adequately protect our interests in disputes with foreign partners and others.

In the international petroleum industry, most production is bought and sold in U.S. currency or with reference to U.S. currency. Accordingly, we do not expect to face foreign exchange risks if and when we commence large-scale commercial production. Most of our business transactions are conducted in U.S. currency in the countries in which we operate.

We currently have minimal debt obligations and, therefore, we do not believe that we face any undue financial risk from interest rate fluctuations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Related Information

INDEPENDENT AUDITORS' REPORT

To the Shareholders of
Ivanhoe Energy Inc.:

We have audited the consolidated balance sheets of Ivanhoe Energy Inc. as at December 31, 2003 and 2002 and the consolidated statements of loss and deficit and cash flow for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada and the United States of America. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Ivanhoe Energy Inc. as at December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta, Canada
February 26, 2004

(signed) Deloitte & Touche LLP
Chartered Accountants

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA — U.S. REPORTING DIFFERENCES

In the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) outlining changes in accounting principles that have been implemented in the financial statements. As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations to conform to the new Canadian Institute of Chartered Accountants Handbook recommendations Section 3110. Also, as discussed in Note 9, the Company changed its method of accounting for stock-based compensation to conform to the new Canadian Institute of Chartered Accountants Handbook recommendations Section 3870.

Calgary, Alberta, Canada
February 26, 2004

(signed) Deloitte & Touche LLP
Chartered Accountants

IVANHOE ENERGY INC.

Consolidated Balance Sheets
(stated in thousands of U.S. Dollars)

	As at December 31,			
		2003		2002
Assets				
Current Assets				
Cash and cash equivalents	$	14,491	$	3,980
Accounts receivable *(Note 3)*		2,720		2,519
Other		409		691
		17,620		7,190
Long term assets *(Note 19)*		998		462
Oil and gas properties, equipment and GTL investments, net *(Note 4)*		87,956		99,436
	$	106,574	$	107,088
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities	$	4,516	$	4,797
Notes payable - current portion *(Note 5)*		167		500
Convertible debentures *(Note 6)*		-		1,000
		4,683		6,297
Long term debt *(Note 5)*		833		-
Asset retirement obligations *(Note 7)*		521		243
Commitments and contingencies *(Note 17)*				
Shareholders' Equity				
Share capital, issued 161,359,000 common shares; December 31, 2002 144,466,000 common shares *(Note 8)*		160,804		131,112
Deficit		(60,267)		(30,564)
		100,537		100,548
	$	106,574	$	107,088

See accompanying Notes to the Consolidated Financial Statements.

Approved by the Board:

(signed) David Martin
Director

(signed) E. Leon Daniel
Director

IVANHOE ENERGY INC.

Consolidated Statements of Loss and Deficit
(stated in thousands of U.S. Dollars, except per share data)

	Year ended December 31,		
	2003	2002	2001
Revenue			
Oil and gas revenue	$ 9,569	$ 8,329	$ 9,144
Interest income	90	108	578
	9,659	8,437	9,722
Expenses			
Operating costs	4,293	3,841	4,758
General and administrative and project identification	7,919	5,667	8,845
Depletion and depreciation	3,829	3,312	3.241
Write downs and provision for impairment *(Notes 4 and 13)*	23,321	2,436	14,000
	39,362	15,256	30,844
Net Loss *(Note 14)*	29,703	6,819	21,122
Deficit, beginning of year	30,564	23,495	2,373
Loss on acquisition of shares *(Note 8)*	-	250	-
Deficit, end of year	$ 60,267	$ 30,564	$ 23.495
Net Loss per Share *(Note 15)*	$ 0.20	$ 0.05	$ 0.16
Weighted Average Number of Shares (in thousands) *(Note 15)*	150,154	142,314	128,598

See accompanying Notes to the Consolidated Financial Statements.

IVANHOE ENERGY INC.

Consolidated Statements of Cash Flow
(stated in thousands of U.S. Dollars)

	Year ended December 31, 2003	2002	2001
Operating Activities			
Net loss	$ (29,703)	$ (6,819)	$ (21,122)
Items not requiring use of cash			
Write downs and provision for impairment *(Notes 4 and 13)*	23,321	2,436	14,000
Depletion and depreciation	3,829	3,312	3,241
Changes in non-cash working capital items	494	(1,687)	6,314
	(2,059)	(2,758)	2,433
Investing Activities			
Capital spending	(15,391)	(18,828)	(40,504)
Proceeds from sale of assets *(Note 4)*	-	5,351	-
Deposit on investment *(Note 19)*	(500)	-	-
Other	(37)	(65)	(155)
	(15,928)	(13,542)	(40,659)
Financing Activities			
Shares issued on private placements, net of share issue costs	24,070	9,964	17,903
Shares issued on exercise of options and warrants	3,928	119	326
Proceeds from notes *(Note 5)*	1,750	500	-
Payments of notes *(Note 5)*	(1,250)	-	-
	28,498	10,583	18,229
Increase (decrease) in cash and cash equivalents, for the year	10,511	(5,717)	(19,997)
Cash and cash equivalents, beginning of year	3,980	9,697	29,694
Cash and cash equivalents, end of year	$ 14,491	$ 3,980	$ 9,697
Supplementary Information			
Regarding Non-Cash Transactions			
Investing activities, net assets acquired *(Note 4)*			
Overriding royalties	$ -	$ -	$ 2,852
Lease acquisition	-	-	900
Accounts receivable	-	-	200
	$ -	$ -	$ 3,952
Financing activities, non-cash			
Shares issued on coversion of debenture *(Note 6)*	$ 1,000	$ -	$ -
Shares issued as consideration	-	-	3,952
	$ 1,000	$ -	$ 3,952
Included in the above are the following:			
Taxes paid or (refunded)	$ 6	$ (27)	$ 104
Interest paid	$ 96	$ 74	$ 111
Changes in non-cash working capital items			
Accounts receivable	$ (201)	$ (581)	$ 2,794
Other current assets	282	(316)	497
Accounts payable and accrued liabilities	413	(790)	3,023
	$ 494	$ (1,687)	$ 6,314

See accompanying Notes to the Consolidated Financial Statements.

IVANHOE ENERGY INC.

Notes to the Consolidated Financial Statements
(all tabular amounts are expressed in thousands of U.S. Dollars, except per share data)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc., a Canadian company, and its subsidiaries are focused internationally on three major strategies: 1) exploration and development of hydrocarbons 2) enhanced oil recovery and 3) the application of heavy-to-light oil upgrading and gas-to-liquids technologies. Operations are currently carried out in the U.S. and China.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in Canada. The impact of material differences between Canadian and U.S. GAAP on the consolidated financial statements is disclosed in Note 20.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts and other disclosures in these consolidated financial statements. Actual results may differ from those estimates.

Change in Accounting Policy

Prior to January 2003, the Company had estimated its future site restoration and abandonment costs associated with its oil and gas properties and amortized this estimate to operations using the unit-of-production method based upon estimated proved reserves. The provision was included with depletion and depreciation expense.

For fiscal years beginning after January 1, 2004, Canadian GAAP requires that asset retirement costs and liabilities associated with site restoration and abandonment of tangible long-lived assets be initially measured at a fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost are recognized in the results of operations.

The Company has elected early implementation of this accounting policy. Accordingly, effective January 1, 2003, the Company changed its accounting policy to capitalize asset retirement costs as part of the carrying value of its oil and gas properties and adjusted the amount of its site restoration liability to the present value of the liability for the corresponding asset retirement obligation as of this date. The Company has adopted the policy without retroactive adjustment of prior years because implementation of this change had an immaterial effect on the Company's financial position and results of operations in prior years and in the current period (See Notes 4 and 7).

U.S. GAAP for asset retirement obligations conforms in all material respects to Canadian GAAP. Implementation for U.S. GAAP is required for fiscal years beginning after June 2002.

The asset retirement costs are being amortized using the unit of production method based on estimated proved reserves. The amortization expenses and accretion of the liability for the asset retirement obligation are included with depletion and depreciation expense.

Principles of Consolidation

These consolidated financial statements include the accounts of Ivanhoe Energy Inc. and its subsidiaries, all of which are wholly owned. We conduct most exploration, development and production activities in our oil and gas business jointly with others and our accounts reflect only the Company's proportionate interest.

All inter-company transactions and balances have been eliminated for the purposes of these consolidated financial statements.

Foreign Currency Translation

The Company uses the U.S. Dollar as its functional currency since it is the currency in which the worldwide petroleum business denominates its business. Monetary assets and liabilities denominated in foreign currencies are converted at the exchange rate in effect

at the balance sheet date and non-monetary assets and liabilities at the exchange rates in effect at the time of acquisition or issue. Revenues and expenses are converted at rates approximating exchange rates in effect at the time of the transactions. Exchange gains or losses resulting from the translation of foreign currency amounts are reflected in operations.

Cash and Cash Equivalents

Cash and cash equivalents include short-term money market instruments with terms to maturity, at the date of issue, not exceeding 90 days.

Financial Instruments

The fair value of the Company's cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, notes payable, long term debt and convertible debenture approximates the carrying values due to the immediate or short-term maturity of these financial instruments.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development expenditures are capitalized on a country-by-country cost center basis. Such expenditures include land acquisition costs, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both productive and non-productive wells, gathering and production facilities and equipment, and financing and administrative costs related to capital projects. The Company periodically evaluates its unproved properties for exploration and exploitation opportunities. If the Company determines that the exploration or exploitation potential of an unproved property has diminished, all, or a portion, of the costs incurred on such property is impaired and transferred to the carrying value of evaluated oil and gas assets. Proceeds from sales of oil and gas assets are recorded as reductions in the carrying value of oil and gas assets, unless such amounts would significantly alter the rate of depreciation and depletion, whereupon gains or losses would be recognized in income. Maintenance and repair costs are expensed as incurred, while improvements and major renovations are capitalized.

Costs of evaluated oil and gas assets accumulated within each cost center, including a provision for future development costs, are depleted using the unit of production method based on estimated proved reserves. Significant development projects and expenditures on unproved properties are excluded from the depletion calculation until evaluated.

Royalty interests acquired are included in oil and gas properties and recorded at cost.

The carrying value of evaluated oil and gas assets, accumulated within each cost center, net of depletion provided, future income taxes and accumulated impairment provisions, are compared annually to the non-discounted estimated future net revenues from proved reserves (based on year-end non-escalated prices), net of estimated administration and carrying costs, and related production and income taxes ("ceiling test"). Any accumulated costs in excess of the calculated ceiling test are charged to operations as a provision for impairment.

Furniture and Fixtures

Furniture and fixtures are stated at cost. Depreciation is provided on a straight-line basis over the estimated useful life of the respective assets, at rates ranging from three to ten years.

Oil and Gas Revenue

Sales of crude oil and natural gas are recognized in the period in which the product is delivered to the customer.

Loss Per Share

Basic earnings per share is calculated by dividing the net earnings available to common shareholders by the weighted average number of common shares outstanding. Diluted earnings per share reflects the potential dilution that would occur if stock options and warrants were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options and warrants would be used to purchase common shares at the average market price for the period (Note 15).

Income Taxes

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income taxes are recognized to reflect the expected future tax consequences arising from tax loss carry-forwards and temporary differences between the carrying value and the tax basis of the Company's assets and liabilities.

Stock Based Compensation

The Company has an Employees' and Directors' Equity Incentive Plan consisting of stock option, bonus and share purchase incentives (Note 9). The Company accounts for its stock-based compensation using intrinsic-values. Compensation costs are not recognized in the financial statements for stock options granted to employees and directors when granted at market value. Compensation costs are, however, recognized in the financial statements for options granted to non-employees based on the fair value of the options at the date granted. Consideration paid upon exercise of stock options is credited to share capital.

Compensation expenses are recognized when shares are issued from the stock bonus plan. The share purchase portion of the plan has not yet been activated.

3. CONCENTRATION OF CREDIT RISKS

The Company sells oil and natural gas products to pipelines, refineries, major oil companies and foreign national petroleum companies. Where possible, credit is extended based on an evaluation of the customer's financial condition and historical payment record.

The following summarizes the revenue receivable balances and revenues from significant customers:

	Accounts Receivable as at December 31,		Oil and Gas Revenues for the Year Ended December 31,		
	2003	2002	2003	2002	2001
U.S. Customers					
A	$ 407	$ 346	$ 4,392	$ 2,916	$ 2,034
B	175	192	986	1,764	2,500
C	60	63	273	390	554
All Others	15	—	65	29	13
	657	601	5,716	5,099	5,101
China Customer					
A	950	767	4,103	3,230	4,043
	$ 1,607	$ 1,368	$ 9,819	$ 8,329	$ 9,144

Oil and gas revenues for the year ended December 31, 2003 in the table above do not include $0.3 million of oil hedge losses from derivative activities.

Accounts receivable as at December 31, 2003 and 2002 in the table above do not include $0.3 million of costs billed to joint venture partners and other receivables and $0.8 million of advances to partners for joint operations where the Company is not the operator.

4. OIL AND GAS PROPERTIES, EQUIPMENT AND GTL INVESTMENTS

Capital assets categorized by geographic location are as follows:

	December 31, 2003			December 31, 2002		
	U.S.	China	Total	U.S.	China	Total
Oil and gas properties and equipment	$ 85,079	$ 32,840	$ 117,919	$ 76,323	$ 26,617	$ 102,940
Accumulated depletion	(6,442)	(3,804)	(10,246)	(4,036)	(2,326)	(6,362)
Provision for impairment	(34,000)	—	(34,000)	(14,000)	—	(14,000)
	44,637	29,036	73,673	58,287	24,291	82,578
Gas to Liquids Investments:						
Master license	10,000	—	10,000	10,000	—	10,000
Feasibility studies and other deferred costs	4,072	—	4,072	6,603	—	6,603
	14,072	—	14,072	16,603	—	16,603
Support equipment	433	31	464	457	36	493
Accumulated depreciation	(253)	—	(253)	(238)	—	(238)
	180	31	211	219	36	255
	$ 58,889	$ 29,067	$ 87,956	$ 75,109	$ 24,327	$ 99,436

Effective January 1, 2003, the Company capitalized $0.3 million as a result of implementation of a new accounting policy on asset retirement obligations. For the year ended December 31, 2003, $0.1 million of future asset retirement costs was capitalized.

During 2002, the Company sold working interests in the Spraberry field in West Texas for $3.0 million and the Daqing project in China for $2.4 million. The Company retains an overriding royalty in the Daqing project of 4% before cost recovery and 2% thereafter. The sale proceeds were credited to the respective cost centers, (Note 2), as the sales did not represent significant dispositions of the U.S. and China total reserve bases.

Costs as at December 31, 2003 and 2002 of $31.2 million and $46.6 million, respectively, related to unevaluated oil and gas properties are excluded from the depletable cost centers.

For the years ended December 31, 2003 and 2002 general and administrative expenses related directly to acquisition, exploration, development and GTL activities of $1.8 million and $2.6 million, respectively, were capitalized.

Gas-to-Liquids

The Company owns a master license from Syntroleum Corporation permitting the Company to use their proprietary gas-to-liquid process ("GTL") in an unlimited number of projects around the world. The Syntroleum process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop, among other things, clean-burning diesel fuel. In July 2003, the master license was amended in respect of GTL projects in which both the Company and Syntroleum participate such that no additional license fees or royalties will be payable by the Company and that Syntroleum will contribute to any such project the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but the Company would be required to pay the normal license fees and royalties in such projects.

Since 2000, the Company has undertaken detailed project feasibility studies for the construction, operation and cost of world-class GTL plants in Qatar, Egypt, Oman and Bolivia. In addition, the Company conducted marketing, commercialization and transportation feasibility studies. Marketing studies were conducted for both Europe and the Asia-Pacific regions for GTL diesel and naphtha. Markets within these regions were identified and premiums for the GTL ultra clean fuels were estimated. Product forecasts from these studies were used to complete studies with various Japanese companies to optimize the commercial structure for utilization of GTL diesel and NGL products.

As a result of the cancellation of Syntroleum's Sweetwater project in Australia in 2002 and the termination of contract negotiations with Qatar Petroleum and the Qatari government to construct and operate a major GTL production facility in Qatar without an agreement being reached in May 2003, the Company has written down $2.4 million and $3.3 million, respectively, of its GTL investment. Costs associated with the feasibility studies and other such related costs remain capitalized. Recovery of the GTL costs capitalized is dependent upon finalizing contracts to access natural gas reserves in the respective countries and the successful completion of GTL processing plants.

United States

In 1998, the Company acquired rights to an exploration agreement ("Agreement") with Aera Energy LLC ("Aera"), which gave the Company access to all of Aera's exploration, seismic and technical data in southern San Joaquin Valley in California for the purpose of identifying drillable exploration prospects within the exclusive area. The Agreement provided the Company the right to a working interest ownership in all drillable prospects in which Aera elects to participate equal to a minimum of 12.5% and a maximum of 75%. In those prospects in which Aera elects not to participate, the Company has the right to proceed with a 100% working interest and to seek other joint venture partners. Aera has the right to act as the operator for any drillable prospects in which Area elects to participate.

The Company has identified 12 prospect Areas of Mutual Interest ("AMIs") containing a total of 30 drillable prospects in which Aera has elected to participate under the Agreement. The Company's working interests, in these AMIs, range from 12.5% to 50%. The Company has a 100% working interest in 3 AMIs in which Aera has declined to participate. In participation with Aera, the Company has drilled 3 wells in the AMIs, 2 of which were unsuccessful and 1, the Northwest Lost Hills #1-22 deep gas well, has been temporarily abandoned. In the AMIs in which Aera has declined to participate, the Company has drilled 51 producing wells in South Midway and one well in the Citrus prospect, which is currently on production and being evaluated.

The Company has drilled 27 producing wells in the Spraberry field and 5 producing wells in the Apache Flats field in West Texas with non-operating working interests of 62.5% and 96.15% in Spraberry and 40% in Apache Flats. In 2002, the Company sold its interests in 7 Spraberry wells for $1.4 million and 50% of its interests in the remaining 20 Spraberry wells for $1.6 million.

The Company leased mineral rights in East Texas and entered into joint venture agreements with a subsidiary of Unocal Corp.

("Unocal") under which Unocal will earn a 50% interest in the Company's holdings by expending the next $10.1 million of costs associated with exploration and development of prospects. Unocal has drilled three wells in two prospects and has spent $8.5 million. The Company has farmed out its interests in the wells, one of which is producing commercial quantities of gas and the other two are in various stages of testing and evaluation.

Provision for impairment amounts calculated for U.S. oil and gas properties is $20.0 million and $14.0 million for 2003 and 2001, respectively. No provision for impairment of oil and gas properties was required for 2002. (See Note 13.)

China

The Company currently holds a production-sharing contract to develop existing oil properties in the Dagang region. The Company has been operating the Dagang field under a pilot phase program since 2000 and in 2003 received final governmental approval for its Overall Development Program (ODP) of the field. In January 2004, the Company signed farm-out and joint operating agreements with a wholly-owned subsidiary of China International Trust and Development Corporation ("CITIC") to acquire a forty percent working interest in the Dagang project for an up-front payment of $20.0 million. The Company and CITIC will incur 100% of the costs to earn 82% of the production, before recovery of costs incurred, reverting to a 49% share post recovery. (See Note 19.)

Prior to 2002, the Company held a contract to develop existing oil fields in the Daqing region and the pilot program was completed successfully in 1998. In January 2002, the Company was successful in disposing of the project for $2.4 million and retains an overriding royalty on future production.

During the pilot testing phase at Dagang and Daqing all production costs net of revenues were capitalized to oil and gas properties and equipment. With the evaluation stage completed and the decision to enter the development and implementation stage, all operating results beginning January 1, 2001 for Dagang and March 1, 2001 for Daqing are included in the Company's results of operations.

In September 2002, the Company signed a 30-year production-sharing contract with PetroChina Corporation ("PetroChina"). The contract area, known as the Zitong block, is located in the northwestern portion of the Sichuan Basin. Under the terms of the contract, the Company will develop natural gas deposits within the block and in return will receive approximately 75% of the revenue until costs are recovered and approximately 45% thereafter. PetroChina has the option to participate in any successful developments, with up to a 51% working interest. In addition, pursuant to existing exclusive arrangements, the Company has the right to negotiate a production-sharing contract for the Yudong block located on the eastern edge of the Sichuan Basin.

Overriding Royalties

Through a series of transactions from 1999 to 2001, the Company acquired overriding royalties in the AMI prospects and other properties in California ranging from 1.46% to 6.58% in consideration for $0.9 million cash and the issuance of 2,885,000 common shares at an aggregate ascribed value of $8.0 million, being 1,562,000 common shares at $2.02; 523,000 common shares at $1.76 and 800,000 common shares at $4.94. Of the total consideration paid, $0.9 million was allocated to property acquisition costs and $0.2 million to accounts receivable.

5. NOTES PAYABLE

The Company borrowed $1.25 million from a related party at U.S. prime plus 3%. The unsecured loan, due 90 days after written demand or on the closing date of obtaining equity financing or December 31, 2005, whichever occurs earliest, was repaid with accrued interest in September 2003. The Company negotiated a revolving credit facility of $1.25 million to re-establish or extend that loan in the future as needs arise.

In February 2003, the Company obtained a bank facility for up to $5.0 million to drill 30 new oil wells and upgrade surface transmission and steam injection facilities in the southern expansion of South Midway. Interest only is payable until June 30, 2004 at 0.25% above the bank`s prime rate or 2.75% over the London Inter-Bank Offered Rate ("LIBOR") at the option of the Company. After June 30, 2004, the loan is repayable over three years plus interest at 0.50% above the bank's prime rate or 3.0% over LIBOR, at the option of the Company. The loan is secured by all the Company's rights and interests in the South Midway properties. The loan balance as at December 31, 2003 is $1.0 million with a three-month fixed LIBOR rate of 4.00%.

The scheduled maturities of the bank loan payable at December 31, 2003 are as follows:

2004	$ 167
2005	333
2006	333
2007	167
	$ 1,000

6. CONVERTIBLE DEBENTURE

In June 2003, the lender elected to convert the $1.0 million unsecured convertible debenture into two million of the Company's common shares at $0.50 per share. All accrued interest on the debenture was paid as of the conversion date.

7. ASSET RETIREMENT OBLIGATION

Effective January 2003, the Company changed its policy on accounting for liabilities associated with site restoration and abandonment of its oil and gas properties. The undiscounted amount of expected cash flows required to settle the asset retirement obligations is estimated at $1.0 million to be settled over a twelve-year period starting in 2010. The liability for the expected cash flows, as reflected in the financial statements, has been discounted at 7%. Implementation of the policy resulted in an additional provision for asset retirement of $0.2 million. For the year ended December 31, 2003, $0.1 million was added to the carrying amount of the asset retirement obligations.

8. SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

The total number of issued and outstanding common shares is as follows:

	Number of Common Shares	Amount
	(thousands)	
Balance December 31, 2000	126,874	$ 98,211
Issued for private placements, net	11,260	17,903
Issued on exercise of warrants	127	166
Issued on exercise of options	206	160
Issued on acquisition of overriding royalties *(Note 4)*	800	3,952
Balance December 31, 2001	139,267	120,392
Issued for private placements, net	5,000	9,964
Issued on exercise of options	163	119
Issued for services	201	387
Elimination of employee loans	--	409
Retirement of shares	(165)	(159)
Balance December 31, 2002	144,466	131,112
Issued for private placements, net	12,654	24,070
Issued on conversion of debenture (Note 6)	2,000	1,000
Issued on exercise of warrants	250	425
Issued on exercise of options	1,363	3,502
Issued for services	626	695
Balance December 31, 2003	161,359	$ 160,804

The Company loaned $0.4 million to an employee and two directors to facilitate their exercise of stock options and warrants to purchase 165,000 common shares of the Company. The Company held the shares as collateral for the loans. The loan balances were previously netted against the share capital balances. In December 2002, the Company determined the loans would not be renewed when they became due in December 2002 and January 2003. Each of the borrowers authorized the Company to acquire the shares held as collateral in full payment of their loan amounts and accrued interest, thereon. Subsequently, the Company eliminated the loans and retired the 165,000 common shares at the average price of all common shares then issued and outstanding ($0.96 per share) and recorded a $0.25 million loss to retained earnings.

Private Placements and Share Purchase Warrants

Under private placements in 2001 and 2002, the Company issued 11.3 million common shares at $1.60 and 5.0 million common shares at $2.00, for net proceeds of $17.9 million and $10.0 million, respectively.

In 2003, the Company closed four special warrant financings to advance its worldwide exploration and production, enhanced oil recovery and GTL activities, to pay down or restructure certain business indebtedness and for general working capital purposes. The financings consisted of 12.7 million special warrants from $1.00 to $4.00 per special warrant. Each special warrant entitles the holder to acquire one common share and purchase warrants, at no additional cost. The purchase warrants are exercisable to purchase additional common shares through the anniversary dates of the special warrant financing at the price per share as indicated in the following table:

Remaining Number of Purchase Warrants	Number of Common Shares	First Anniversary Date	First Anniversary Price per Share (US$)	Second Anniversary Date	Second Anniversary Price per Share (US$)
(thousands)					
3,000	1,500	July 3, 2004	$1.00	July 3, 2005	$1.10
3,000	1,500	August 18, 2004	$1.00	August 18, 2005	$1.10
3,029	1,515	August 21, 2004	$1.70	August 21, 2005	$1.87
3,125	1,250	October 31, 2004	$4.00	October 31, 2005	$4.30

In November 2003, 500 thousand purchase warrants for $1.70 per share were exercised for the purchase of 250 thousand shares.

9. STOCK BASED COMPENSATION

The Company has an Employees' and Directors' Equity Incentive Plan under which it can grant stock options to directors, officers and employees to purchase common shares, issue common shares to directors and employees for bonus awards and issue shares under a share purchase plan for employees.

Stock options are issued at not less than the quoted market value on the date of the grant and are conditional on continuing employment. Expiration and vesting periods are set at the discretion of the Board of Directors. Options granted prior to March 1, 1999 vested over a two-year period and expire ten years from date of issue. Options granted after March 1, 1999 vest over four years and expire five years from the date of issue.

Following is a summary of the stock option portion of the Company's Equity Incentive Plan, including changes during the years ended:

	December 31, 2003		December 31, 2002		December 31, 2001	
	Number of Options (000's)	Weighted-Average Exercise Price (Cdn.$)	Number of Options (000's)	Weighted-Average Exercise Price (Cdn.$)	Number of Options (000's)	Weighted-Average Exercise Price (Cdn.$)
Outstanding at beginning of year	10,265	$ 2.69	8,635	$ 2.66	8,161	$ 2.45
Granted	840	$ 4.95	2,095	$ 2.86	846	$ 4.63
Exercised	(1,363)	$ 3.39	(164)	$ 1.57	(206)	$ 1.40
Cancelled/forfeited	(793)	$ 4.42	(301)	$ 3.48	(166)	$ 4.04
Outstanding at end of year	8,949	$ 2.64	10,265	$ 2.69	8,635	$ 2.66
Options exercisable at year end	6,974	$ 2.20	7,122	$ 2.13	6,089	$ 1.73

Effective January 2002, Canadian accounting standards require disclosure, on a pro forma basis, of the impact on net income of using the fair value method for stock options granted to employees and directors on or after that date. The Company accounts for its stock-based compensation plans using the intrinsic-value of the options. Under this method, compensation costs are not recognized in the financial statements for share options granted to employees and directors when issued at market value. Had stock based compensation expense been determined based on the fair value at the option grant date, the Company’s net loss and net loss per share for the years ended December 31 2003 and 2002 would have been as follows:

	Year ended December 31, 2003	Year ended December 31, 2002
Pro forma net loss	$30,179	$7,130
Pro forma net loss per share	$0.20	$0.05

The foregoing is calculated in accordance with Black-Scholes options pricing model, using the following data and assumptions: 72% to 100% price volatility, using the prior two years weekly average prices of the Company’s common shares; expected dividend yield of 0%; option terms to expiry of 5 years, as defined by the option agreements; risk-free rate of return as of the date of the grant of 4.08% to 5.58%, based on one and five year Government of Canada Bond yields.

The following table summarizes information respecting stock options outstanding as at December 31, 2003:

Range of Exercise Prices (Cdn.$)	Options Outstanding: Number Outstanding (000's)	Options Outstanding: Weighted-Average Remaining Contractual Life Yrs.	Options Outstanding: Weighted-Average Exercise Price (Cdn.$)	Options Exercisable: Number Exercisable (000's)	Options Exercisable: Weighted-Average Exercise Price (Cdn.$)
$0.50 to $2.00	4,286	4.6	$ 0.62	4,001	$ 0.55
$2.50 to $3.60	2,360	2.1	$ 2.89	1,584	$ 2.76
$5.15 to $7.60	2,303	2.7	$ 6.16	1,389	$ 6.30
$0.50 to $7.60	8,949	3.4	$ 2.64	6,974	$ 2.20

10. RETIREMENT PLAN

In 2001, the Company adopted a defined contribution retirement or thrift plan (401(k) Plan) to assist U.S. employees in providing for retirement or other future financial needs. Employees' contributions (up to the maximum allowed by U.S. tax laws) are matched 50% by the Company in 2001 and increasing 10% per year thereafter to a maximum of 100%. The Company's matching contributions to the 401(k) Plan during 2003, 2002 and 2001 were $0.2 million for 2003 and $0.1 million per year for 2002 and 2001.

11. SEGMENT INFORMATION

Geographic segment results from operations for the years ended December 31, 2003, 2002 and 2001 are detailed below. The Company maintains a corporate office in Canada with its operational office in the U.S. For this section any amounts for Canada are included in the U.S. segment.

	Year ended December 31, 2003		
	U.S.	**China**	**Total**
Oil and gas revenue	$ 5,466	$ 4,103	$ 9,569
Interest income	90	-	90
	5,556	4,103	9,659
Operating costs	2,313	1,980	4,293
Depletion and depreciation	2,351	1,478	3,829
Provision for impairment *(Note 13)*	20,000	-	20,000
	24,664	3,458	28,122
Segment loss (income) before the following	$ 19,108	$ (645)	18,463
Write down of GTL assets *(Note 4)*			3,321
General and administrative and project identification			7,919
Net loss			$ 29,703
Capital expenditures:			
Oil and gas	$ 8,386	$ 6,213	$ 14,599
Gas-to-liquids			792
			$ 15,391
Identifiable Assets:			
Oil & gas	$ 61,379	$ 30,766	$ 92,145
Gas-to-liquids			14,429
			$ 106,574

	Year ended December 31, 2002		
	U.S.	China	Total
Oil and gas revenue	$ 5,099	$ 3,230	$ 8,329
Interest income	108	-	108
	5,207	3,230	8,437
Operating costs	2,351	1,490	3,841
Depletion and depreciation	2,110	1,202	3,312
	4,461	2,692	7,153
Segment income before the following	$ 746	$ 538	1,284
Write down of GTL assets *(Note 4)*			2,436
General and administrative and project identification			5,667
Net loss			$ 6,819
Capital expenditures:			
Oil and gas	$ 13,305	$ 3,626	$ 16,931
Gas-to-liquids			1,897
			$ 18,828
Identifiable Assets:			
Oil and gas	$ 64,448	$ 25,281	$ 89,729
Gas-to-liquids			17,359
			$ 107,088

	Year ended December 31, 2001		
	U.S.	China	Total
Oil and gas revenue	$ 5,101	$ 4,043	$ 9,144
Interest income	578	-	578
	5,679	4,043	9,722
Operating costs	2,421	2,337	4,758
Depletion and depreciation	2,117	1,124	3,241
Provision for impairment *(Note 13)*	14,000	-	14,000
	18,538	3,461	21,999
Segment loss (income) before the following	$ 12,859	$ (582)	12,277
General and administrative and project identification			8,845
Net loss			$ 21,122
Capital expenditures:			
Oil and gas	$ 33,799	$ 6,568	$ 40,367
Gas-to-liquids			3,889
			$ 44,256
Identifiable Assets:			
Oil and gas	$ 61,750	$ 25,067	$ 86,817
Gas-to-liquids			17,186
			$ 104,003

12. DERIVATIVE ACTIVITIES

The Company's results of operations are sensitive mainly to fluctuations in oil and natural gas prices. The Company may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows.

The Company entered into costless collar derivatives to hedge its cash flow from the sale of 500 barrels of oil production per day over two six-month periods starting October 2002 and June 2003. The derivatives had ceiling prices of $30.45 and $28.95 per barrel for the June 2003 and October 2002 contracts, respectively, and a floor price of $24.00 per barrel using WTI as the index traded on the NYMEX. Gains and losses on derivatives are recognized in earnings as they are realized. For the year ended December 31, 2003, the Company had realized losses of $0.3 million on derivative transactions. The Company had insignificant realized derivative losses for the year ended December 31, 2002. The derivative losses are included in oil and gas revenue.

In conjunction with the October 2002 hedge, the Company posted collateral of $0.6 million as security for the hedge. The collateral accrued interest at the U.S. Federal Funds rate. The collateral was returned upon maturity of the hedge contract in April 2003. As at December 31, 2002, the $0.6 million collateral is included in other current assets.

The mark-to-market value of the derivatives is a liability of $0.1 million as at December 31, 2002. There are no hedge contracts outstanding as at December 31, 2003.

13. PROVISION FOR IMPAIRMENT

The $20.0 million provision for impairment for 2003 is due mainly to an increase in the carrying costs of the Company's evaluated U.S. oil and gas assets primarily in East Texas, Northwest Lost Hills and other California prospects when compared to the estimated recoverable value of its U.S. proved reserves as at December 31, 2003. Such carrying costs increased as a result of the decision, in the fourth quarter of 2003, to potentially farm-out up to 50% of the Company's working interest to one or more partners to fund a test of Northwest Lost Hills # 1-22. Additionally, evaluation of significant portions of the Company's acreage positions in East Texas and the southern San Joaquin Valley in California was completed in 2003 and either have been, or will be, relinquished, thus adding to the carrying value of the Company's evaluated U.S. oil and gas assets. The $14.0 million impairment for 2001 was mainly due to a decline in oil and gas prices thus reducing the estimated recoverable value of proved reserves as at December 31, 2001.

14. INCOME TAXES

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. Details of the determination of the actual income tax expense for each of the three years are detailed below. The loss of approximately $35.0 million from the Russian operations in 2000, being the aggregate investment, not including accounting write-downs, less proceeds received on settlement is a capital loss for Canadian income tax purposes, available for carry-forward against future Canadian capital gains indefinitely.

	Year ended December 31,		
	2003	2002	2001
Loss before income taxes	$ 29,703	$ 6,819	$ 21,122
Composite statutory income tax rate	43.20%	43.20%	43.20%
Expected income tax recovery	$ (12,832)	$ (2,946)	$ (9,125)
Tax benefit not recognized:	12,832	2,946	9,125
Income tax expense	$ —	$ —	$ —

The tax loss carry-forwards in Canada are Cdn. $51.8 million and in the U.S. $57.7 million. The tax loss carry-forwards in Canada expire between 2004 and 2010 and in the U.S. between 2018 and 2023. In China, the Company has available for carry-forward against future Chinese income $42.2 million of cost basis. The Company's carrying value of assets for accounting purposes is $23.0 million greater than that available for tax purposes.

Due to the uncertainty of utilizing these net tax assets, the Company has made a valuation allowance of an equal amount against these potential recoverable amounts as detailed below.

	As at December 31,		
	2003	2002	2001
Future net tax assets	$ 40,500	$ 31,607	$ 27,082
Valuation allowance	(40,500)	(31,607)	(27,082)
Net future tax liability	$ —	$ —	$ —

15. NET LOSS PER SHARE

Had the Company generated net earnings during the years presented, the earnings per share calculations for the years presented would have included the following weighted average items:

	Year ended December 31, (000's)		
	2003	2002	2001
Warrants	556	—	—
Convertible debenture	499	1,299	545
Stock options	3,535	2,986	4,018
	4,590	4,285	4,563

Additionally, the earnings per share calculations would not have included the following weighted average items because the exercise prices exceeded the average market prices of the common shares:

	Year ended December 31, (000's)		
	2003	2002	2001
Warrants	140	—	2,500
Convertible debenture	306	—	—
Stock options	3,802	5,359	240
	4,248	5,359	2,740

16. RELATED PARTY TRANSACTIONS

The Company has entered into agreements with a number of entities, some of which are related through common directors or shareholders, to share administrative personnel, aircraft, office space and facilities. The agreement for the usage of aircraft was terminated in 2003. The Company is billed on a cost recovery basis. The costs incurred in the normal course of business with respect to the above arrangements amounted to $0.9 million for 2003, $1.2 million for 2002 and $2.7 million for 2001. In addition, a company controlled by a director provides consulting services to the Company. Consulting services and out of pocket expenses paid to this company were $0.4 million for 2003 and 2002 and $0.7 million for 2001. At year-end, amounts included in accounts payable under these arrangements totaled $0.1 million in 2003, $0.8 million in 2002 and $1.1 million in 2001.

The Company borrowed $1.25 million from a related company controlled by a director of the Company. The loan, plus accrued interest, was repaid in September 2003. (See Note 5)

17. COMMITMENTS AND CONTINGENCIES

With the signing of the production-sharing contract in September 2002 for the Zitong block, the Company is obligated to conduct a minimum exploration program during the first three years, which will include acquiring seismic data, reprocessing existing seismic and drilling two exploration wells. At the end of the three-year period, if the Company does not complete the minimum exploration program, and elects not to continue, it will be obligated to pay, to PetroChina within 30 days, a cash equivalent of the deficiency in the work program. The remaining cost of the minimum exploration program is estimated to be at least $16.6 million as at December 31, 2003.

The Company has temporarily abandoned Northwest Lost Hills #1-22 pending the identification of one or more partners to share the costs of the testing program. If the well were permanently abandoned, the Company would be obligated for its share of the costs to plug and abandon the well, which is estimated to be $1.1 million. There is no provision in the balance sheet for this contingent obligation.

18. LEASE COMMITMENTS

For the years ended December 31, 2003, 2002 and 2001, the Company expended $0.5 million, $0.6 million and $0.6. million, respectively, on operating leases relating to the rental of office space, which expire between April 2005 and March 2007. Such leases frequently provide for renewal options and require the Company to pay for utilities, taxes, insurance and maintenance expenses. As at December 31, 2003, future net minimum lease payments for operating leases (excluding oil and gas and other mineral leases) were the following:

2004	$ 533
2005	442
2006	306
2007	51
Total minimum lease payments	$ 1,332

19. SUBSEQUENT EVENTS

In January 2004, the Company signed a Stock Purchase and Shareholders' Agreement with Ensyn Group Inc. and its subsidiary, Ensyn Petroleum International Ltd ("Ensyn"), pursuant to which we acquired a 10% equity interest in Ensyn and exclusive rights to use the proprietary Ensyn RTP™ Process in several key international markets. The Company will pay $2.0 million and grant Ensyn rights to acquire equity interests in the Company's international oil development projects that use the Ensyn RTP™ Process. The purchase price for the 10% equity interest in Ensyn will be paid in four equal installments and completion of the acquisition is subject to the attainment of specific milestones: (1) upon signing the heads of agreement, (2) upon signing the Stock Purchase and Shareholders' Agreement, (3) upon Ensyn delivering a commercial demonstration facility to California and (4) upon confirmation of the economic viability of the Ensyn RTP™ Process from the commercial demonstration facility. The first payment of $0.5 million was made in December 2003 and is included in long-term assets.

In January 2004, the Company signed farm-out and joint operating agreements with Richfirst Holdings Limited ("Richfirst"), a wholly-owned subsidiary of CITIC to jointly develop the Dagang oil project, operated by the Company's wholly owned subsidiary, Sunwing Energy Ltd ("Sunwing"). Richfirst will acquire a 40% working interest in the project following regulatory approvals and an up-front payment of $20.0 million. The assignment of the interest to Richfirst is subject to the approval of China National Petroleum Corporation and the Ministry of Commerce of the People's Republic of China. The farm-out agreement permits Richfirst to exchange its working interest in the Dagang Project for common shares in the Company or Sunwing, should the Company seek and secure a public listing for Sunwing.

In February 2004, the Company farmed into the Knights Landing project, which is a 14,000-acre block located in the Sutter and Yolo counties, in northern California. Under this exploration and development farm-in agreement, the Company purchased, for $1.0 million, a 50% non-operated interest in four recent discoveries in the contract area and agreed to fund, for $0.6 million, gas gathering, surface treatment facilities and meters to connect the four wells to an existing pipeline system. The agreement also provides for the Company to participate, at its election, in drilling additional exploration wells in the lease block.

In February 2004, the Company arranged a special warrant financing to advance the Company's worldwide oil and gas operations and for general corporate purposes. The financing consists of 5,448,276 million special warrants at $2.90 per special warrant. Each special warrant entitles the holder to acquire one common share and one-half of a common share purchase warrant at no additional cost. One common share purchase warrant is exercisable to purchase an additional common share at $3.00 until February 15, 2005 and at $3.20 until February 15, 2006.

20. ADDITIONAL DISCLOSURES REQUIRED UNDER U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")

The Company's consolidated financial statements have been prepared in accordance with GAAP as applied in Canada. In the case of the Company, Canadian GAAP conforms in all material respects with U.S. GAAP except for certain matters, the details of which are as follows:

Consolidated Statements of Loss

As discussed under "Oil and Gas Properties" in this note, there is a difference in performing the ceiling test evaluation under full cost accounting between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP as at December 31, 2001 required an additional $10.0 million provision for impairment with respect to the Company's China properties.

The capitalization of development costs permitted under Canadian GAAP in connection with our GTL prospects is not permitted under U.S. GAAP. In addition, under U.S. GAAP interest income would be classified as other income.

The application of U.S. GAAP has the following effects on net loss and net loss per share as reported:

	Year ended December 31,		
	2003	2002	2001
Net loss under Canadian GAAP	$ 29,703	$ 6,819	$ 21,122
Additional provision for impairment of China properties under U.S. GAAP	—	—	10,000
Depletion adjustment - China	(88)	(78)	—
Write-down of GTL development costs under U.S. GAAP, net	(2,529)	1,461	5,142
Net loss under U.S. GAAP	$ 27,086	$ 8,202	$ 36,264
Net loss per share under U.S. GAAP Basic	$ 0.18	$ 0.06	$ 0.28
Weighted average shares outstanding under U.S. GAAP (in thousands) Basic	150,154	142,314	128,598

Under U.S. GAAP, changes in the fair value of derivative instruments that meet specific cash-flow hedge accounting criteria are reported in other comprehensive income (OCI). The gains and losses on cash-flow hedge transactions that are reported in OCI are reclassified to earnings in the period in which earnings are affected by changes in the cash flow of the underlying hedged item. The Company's hedging contracts qualify for hedge accounting treatment. The mark-to-market value of these derivatives as at December 31, 2002 is a liability of $0.1 million, which comprises the balance of OCI as at December 31, 2002.

Stock based compensation

The Company has a stock-based compensation plan as more fully described in Note 9. With regards to its stock option plan, the Company applies APB Opinion No. 25, as interpreted by FASB ("FIN") 44, in accounting for this plan and accordingly no compensation cost has been recognized for stock options issued to employees and directors. Had compensation expense been determined based on fair value at the stock option grant date, consistent with the method of SFAS No. 123, Accounting for Stock-Based Compensation, the Company's net loss and net loss per share would have been increased to the pro forma amounts indicated below:

	Year ended December 31,		
	2003	2002	2001
Net loss under U.S. GAAP	$ 27,086	$ 8,202	$ 36,264
Stock-based compensation expense determined under fair-value based method for all awards	1,682	1,885	1,827
Pro forma net loss under U.S. GAAP	$ 28,768	$ 10,087	$ 38,091
Net loss per common share under U.S. GAAP:			
Basic – as reported	$ 0.18	$ 0.06	$ 0.28
Basic – pro forma	$ 0.19	$ 0.07	$ 0.30
Stock options granted during period (thousands)	690	1,870	846
Weighted average exercise price	$ 4.00	$ 1.92	$ 2.99
Weighted average fair value of options granted during the period	$ 2.83	$ 1.07	$ 1.92

The foregoing is calculated in accordance with Black-Scholes option pricing model, using the following data and assumptions: 59% to 108% price volatility, using the prior one to three-year weekly average prices of the Company's common shares; expected dividend yield of 0%; option terms to expiry of 5 to 10 years, as defined by the option agreements; risk-free rate of return as of the date of the grant of 4.08% to 5.70%, based on one and four year Government of Canada Bond yields.

Consolidated Balance Sheets

The application of U.S. GAAP would have the following effects on balance sheet items as reported:

Shareholders' Equity

Shareholders' equity at December 31, 2003 under Canadian GAAP	$ 100,537
Adjustment to ascribed value of shares issued for royalty interests	1,358
Impairment provision for China properties required under U.S. GAAP	(10,000)
Depletion adjustment - China	166
Write-down of GTL development costs required under U.S. GAAP	(4,074)
Shareholders' equity at December 31, 2003 under U.S. GAAP	$ 87,987

Shareholders' equity at December 31, 2002 under Canadian GAAP	$ 100,548
Adjustment to ascribed value of shares issued for royalty interests	1,358
Impairment provision for China properties required under U.S. GAAP	(10,000)
Depletion adjustment - China	78
Write-down of GTL development costs required under U.S. GAAP	(6,603)
OCI – Derivative mark- to-market adjustment	(102)
Shareholders' equity at December 31, 2002 under U.S. GAAP	$ 85,279

The shareholders approved, on June 22, 1999, the reduction of stated capital in respect of the common shares by an amount of $74.4 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the deficit such as this is

not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and deficit each are increased by $74.4 million at December 31, 2003 and 2002. As a result, shareholders' equity under U.S. GAAP would comprise the following:

	As at December 31,	
	2003	2002
Share capital (including adjustments above)	$ 236,617	$ 206,925
Deficit (including adjustments above)	(148,630)	(121,544)
Accumulated other comprehensive income	—	(102)
	$ 87,987	$ 85,279

Oil and Gas Properties

There are certain differences between the full cost method of accounting for oil and gas assets as applied in Canada and as applied in the U.S. The principal difference results in the method of performing ceiling test evaluations under the full cost accounting rules. Under Canadian GAAP, non-discounted future net revenues from oil and gas production, less an estimate for future general and administrative expenses, financing costs and income taxes are compared to the carrying value of the evaluated oil and gas assets, whereas for U.S. GAAP future net revenues are discounted to present value at 10% per annum and compared to the carrying value of the evaluated oil and gas assets. The Company has performed the ceiling test in accordance with U.S. GAAP and determined that there would be an additional provision for impairment required in connection with the Company's China properties of $10.0 million for 2001. No additional impairment provisions are required for 2003, and no impairment provision was required for 2002.

For U.S. GAAP purposes, the aggregate value attributed to the acquisition of royalty rights is $1.4 million higher, due to the difference between Canadian and U.S. GAAP in the value ascribed to the shares issued, primarily resulting from differences in the recognition of effective dates of the transactions.

The categories of costs included in the cost of oil and gas properties, equipment and GTL investments, including the adjustments in accordance with U.S. GAAP, to the ascribed value of shares issued for royalty interests of $1.4 million, an additional provision for impairment of the Company's China properties of $10.0 million and the write-down of GTL development costs are as follows:

	As at December 31,		
	2003	2002	2001
Property acquisition costs	$ 17,518	$ 16,868	$ 15,956
Royalty rights acquired	10,582	10,582	10,582
Exploration costs	34,908	31,760	20,918
Development costs	56,269	45,088	45,325
GTL license	10,000	10,000	12,000
Support equipment	464	493	468
	129,741	114,791	105,249
Accumulated depletion and depreciation	(10,334)	(6,523)	(3,437)
Provision for impairment	(44,000)	(24,000)	(24,000)
	$ 75,407	$ 84,268	$ 77,812

Development costs as at December 31, 2003 include $0.4 million of asset retirement costs.

As at December 31, 2003, the costs of unevaluated properties included in capital assets are as follows:

		Incurred In			
	Total	2003	2002	2001	Prior to 2001
Property acquisition costs	$ 9,874	$ 2,318	$ 1,686	$ 4,642	$ 1,228
Royalty rights acquired	8,095	—	—	3,509	4,586
Exploration costs	14,562	2,925	4,008	4,222	3,407
	$ 32,531	$ 5,243	$ 5,694	$ 12,373	$ 9,221

Accounts payable and accrued liabilities

The following is the breakdown of accounts payable and accrued liabilities:

	As at December 31,	
	2003	2002
Accounts payable	$ 3,626	$ 4,387
Accrued salaries and related expenses	858	348
Fair market value of oil hedge	—	102
Accrued interest	2	10
Other accruals	30	52
Total	$ 4,516	$ 4,899

Consolidated Statements of Cash Flow

As a result of the write-down of GTL development costs required under U.S. GAAP, the statement of cash flow as reported would result in cash deficiencies from operating activities of $2.9 million, $4.7 million and $1.5 million for the years ended December 31, 2003, 2002 and 2001, respectively, and capital spending reported under investing activities would be $14.6 million, $16.9 million and $36.6 million for the same periods ended, respectively.

Impact of New and Pending U.S. GAAP Accounting Standards

The following standards issued by the FASB do not impact us:

- Interpretation No. 46, "Consolidation of Variable Interest Entities", effective for financial statements issued after January 31, 2003.
- SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity", effective for financial statements issued after June 15, 2003.
- SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Post Retirements Benefits – an amendment of SFAS No. 87, 88 and 106", effective for financial statements issued after December 15, 2003.
- SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", effective for contracts entered into or modified after June 30, 2003.

QUARTERLY FINANCIAL DATA IN ACCORDANCE WITH CANADIAN AND U.S. GAAP (UNAUDITED)

	QUARTER ENDED							
	March 31		June 30		September 30		December 31	
	2003	2002	2003	2002	2003	2002	2003	2002
Oil and gas revenues..........................	$2,531	$1,663	$2,332	$1,981	$2,405	$2,328	$2,301	$2,357
Operating profit..............................	$1,633	$ 807	$1,384	$ 969	$1,257	$1,258	$1,002	$1,454
Net loss under Canadian GAAP............	$ 998	$1,521	$4,465	$1.107	$1,206	$3,064	$23,034	$1,127
Net loss under U.S. GAAP..................	$1,185	$2,131	$1,325	$1,808	$1,306	$2,976	$23,270	$1,287
Net loss per share under Canadian GAAP	$0.01	$0.01	$0.03	$0.01	$0.01	$0.02	$0.15	$0.01
Net loss per share under U.S. GAAP........	$0.01	$0.02	$0.01	$0.01	$0.01	$0.02	$0.15	$0.01

Notes:

(1) A $20.0 million provision for impairment of U.S. oil and gas assets was recorded in the fourth quarter of 2003.

(2) A $3.3 million write down of costs associated with the unsuccessful negotiation of a GTL contract in Qatar was recorded in the second quarter of 2003 for Canadian GAAP only as GTL costs are written off currently for U.S. GAAP.

(3) A $2.4 million write down of the Sweetwater, Australia GTL assets was recorded in the third quarter of 2002.

SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES (UNAUDITED)

The following information about the Company's oil and gas producing activities is presented in accordance with U.S. Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities".

Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions.

Proved developed oil and gas reserves are reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of oil and gas reserves are subject to uncertainty and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change.

Reserves presented in this section represent the Company's share of reserves, excluding royalty interests of others. The reserves for 2003 in the U.S. are based on the estimates by the independent petroleum engineering firm of Netherland, Sewell & Associates, Inc. The reserves for 2002 and 2001 in the U.S. are based on estimates by the independent petroleum engineering firms of Joe C. Neal & Associates and Allan Spivak Engineering. In China, the reserves are based on estimates by the independent petroleum engineering

firm of Gilbert Laustsen Jung Associates Ltd.

The Company's net proved and net proved developed oil and gas reserves are as follows:

	Oil (MBbl)	Gas (MMcf)
Net proved reserves, December 31, 2000	25,794	6,296
Extensions and discoveries	923	651
Production	(377)	(127)
Revisions to previous estimates	(2,542)	(5,189)
Net proved reserves, December 31, 2001	23,798	1,631
Extensions and discoveries	710	63
Production	(350)	(103)
Revisions to previous estimates	(2,881)	(101)
Sale of reserves	(3,889)	(671)
Net proved reserves, December 31, 2002	17,388	819
Extensions and discoveries	480	22
Production	(346)	(50)
Revisions to previous estimates	(260)	(96)
Net proved reserves, December 31, 2003	17,262	695
Net proved developed reserves:		
December 31, 2001	1,808	1,215
December 31, 2002	1,179	819
December 31, 2003	1,434	695

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The following standardized measure of discounted future net cash flows from proved oil and gas reserves has been computed using period end prices of $30.31 per barrel of oil ($29.04 per barrel in 2002 and $15.37 per barrel in 2001) and $6.13 per Mcf of gas ($5.30 per Mcf in 2002 and $2.76 per Mcf in 2001) and costs and period end statutory tax rates. A discount rate of 10% has been applied in determining the standardized measure of discounted future net cash flows.

The Company does not believe that this information reflects the fair market value of its oil and gas properties. Actual future net cash flows will differ from the presented estimated future net cash flows in that:

- future production from proved reserves will differ from estimated production;
- future production will also include production from probable and potential reserves;
- future rather than year end prices and costs will apply; and
- existing economic, operating and regulatory conditions are subject to change.

The standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years are as follows:

	2003	2002	2001
Future cash inflows	$ 527,499	$ 513,313	$ 370,344
Future development and restoration costs	156,383	134,452	137,581
Future production costs	113,949	150,828	156,103
Future income taxes	61,647	52,656	5,526
Future net cash flows	195,520	175,377	71,134
10% annual discount	96,646	94,110	52,845
Standardized measure	$ 98,874	$ 81,267	$ 18,289

Changes in standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years are as follows:

	2003	2002	2001
Sale of oil & gas net of production costs	$ (5,276)	$ (4,488)	$ (4,386)
Net changes in pricing and productions costs	43,926	164,210	(110,584)
Sale of reserves	—	(47,685)	--
Discoveries and extensions	5,076	9,585	4,955
Revisions of previous estimates	(16,788)	(63,467)	22,167
Net change in future development costs	(12,289)	3,230	(1,640)
Accretion of discount	2,958	1,593	6,541
Increase (decrease)	17,607	62,978	(82,947)
Standardized measure, beginning of year	81,267	18,289	101,236
Standardized measure, end of year	$ 98,874	$ 81,267	$ 18,289

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities are as follows:

	Year ended December 31,		
	2003	2002	2001
Property Acquisition			
Proved	$ —	$ —	$ —
Unproved	650	913	5,688
Royalty rights	—	—	4,043
Exploration	3,148	10,841	11,545
Development	11,181(1)	5,178	19,091
	$ 14,979	$ 16,932	$ 40,367

(1)Development cost additions for the year ended December 31, 2003 include $0.4 million of asset retirement costs.

Depletion, per unit of net production, before provision for impairment:

U.S.	
Year ended December 31, 2003	$10.58
Year ended December 31, 2002	$ 8.39
Year ended December 31, 2001	$ 8.12
China	
Year ended December 31, 2003	$10.23
Year ended December 31, 2002	$ 8.30
Year ended December 31, 2001	$ 6.79

Results of Producing Activities:	Year ended December 31,		
	2003	2002	2001
Oil and gas revenue	$ 9,569	$ 8,329	$ 9,144
Operating costs	4,293	3,841	4,758
Depletion (including provision for impairment)	23,730	3,108	27,133
Results of operations from producing activities	$ (18,454)	$ 1,380	$ (22,747)

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

The Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's CEO and CFO, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to the 1934 Securities Exchange Act. Based upon that evaluation, the CEO and CFO concluded that, as of December 31, 2003, the Company's disclosure controls and procedures are effective in timely alerting them to material information required to be included in the Company's periodic SEC filings relating to the Company (including its consolidated subsidiaries). There were no significant changes in the Company’s internal control over financial reporting or in other factors that could significantly affect its internal control over financial reporting during the year ended December 31, 2003, nor any significant deficiencies or material weaknesses in such internal control over financial reporting requiring corrective actions. As a result, no corrective actions were taken.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides the names of all of our directors and executive officers, their positions, terms of office and their principal occupations during the past five years. Each director is elected for a one-year term or until his successor has been duly elected or appointed. Officers serve at the pleasure of the Board of Directors.

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
DAVID R. MARTIN, age 72 .... Santa Barbara, California	Chairman of the Board and Director (since August, 1998)	Chairman of the Board of Ivanhoe Energy Inc. (August 1998 — present); President, Cathedral Mountain Corporation (1997 — present); President and Chief Executive Officer, Occidental Oil and Gas Corporation (1986-1996); Executive Vice President and Director, Occidental Petroleum Corporation (1986-1996)
ROBERT M. FRIEDLAND, age 53 .... Hong Kong	Deputy Chairman (since June, 1999) and Director (since February, 1995)	Chairman and President, Ivanhoe Capital Corporation, a Singapore based venture capital company principally involved in establishing and financing international mining and exploration companies
E. LEON DANIEL, age 67 .... Park City, Utah	President, Chief Executive Officer (since June, 1999) and Director (since August, 1998)	President and Chief Executive Officer of Ivanhoe Energy Inc. (June, 1999 — present); Executive Vice President, Worldwide Business Development, Occidental Oil and Gas Corporation (1996-1998); Vice President Engineering, Drilling and Production, Occidental Petroleum Corporation (1997-1998)
JOHN A. CARVER, age 71 .... Bakersfield, California	Director (since August, 1998)	Retired (1998); Senior Vice President, Worldwide Exploration, Occidental Petroleum Corporation (1997-1998)
R. EDWARD FLOOD, age 58............ Reno, Nevada	Director (since June, 1999)	Deputy Chairman, Ivanhoe Mines Ltd. (May, 1999 — present); Mining Analyst, Haywood Securities (May, 1999 — September 2001) President, Ivanhoe Mines Ltd. (1995-1999)
SHUN-ICHI SHIMIZU, age 63 .... Tokyo, Japan	Director (since July, 1999)	Managing Director of C.U.E. Management Consulting Ltd. (1994 — present)
HOWARD R. BALLOCH, age 52....... Beijing, China	Director (since January, 2002)	President, The Balloch Group (July 2001 — present); President, Canada China Business Council (July 2001 — present); Canadian Ambassador to China, Mongolia and Democratic Republic of Korea (April 1996 — July 2001)
J. STEVEN RHODES, age 52 .... Los Angeles, California	Director (since December, 2003)	Chairman and Chief Executive Officer. Claiborne-Rhodes, Inc. (2001 — present); Senior Vice President, First Southwest Company (1999— 2001) White House, Chief Domestic Advisor to Vice President George Bush (1981 — 1985)
W. GORDON LANCASTER, C.A. age 60 Vancouver, British Columbia	Chief Financial Officer (Effective January 1, 2004)	Vice President Finance and Chief Financial Officer of Xantrex Technology Inc., (July 2003 — December 2003); Vice President Finance and Chief Financial Officer of Power Measurement, Inc., (August 2000 — June 2003) 2003); Senior President Finance and Chief Financial Officer of Lions Gate Entertainment Corp., (1998 — 2000)
JOHN O'KEEFE, age 55 .... Houston, Texas	Executive Vice-President, Investor Relations and Chief Financial Officer (From September, 2000 to December 2003)	Executive Vice-President, Investor Relations and Chief Financial Officer of Ivanhoe Energy Inc. (September 2000 — December 2003); Vice-President, Investor Relations of Santa Fe Snyder Corporation (1999 — September 2000); Director, Investor Relations of Oryx Energy Company (1991-1999)
PATRICK CHUA, age 48.................... Hong Kong, China	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 — present); President and Director of Sunwing Energy Ltd. (Bermuda) (March 2000 — present): Co-Chairman and Director of Sunwing Energy Ltd. (June, 1996 — June, 1999)
GERALD MOENCH, age 55............... Lethbridge, Alberta	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 — present); President and Director, Sunwing Energy Ltd. (July, 1997 — June, 1999)

Each of our directors was elected at our last annual general meeting of shareholders held on June 19, 2003. The term of office of each director concludes at our next annual general meeting of shareholders, unless the director's office is earlier vacated in accordance with our by-laws. There are no family relationships among any of our directors, officers or key employees.

As required under the *Business Corporations Act* (Yukon), our Board of Directors has an Audit Committee. We also have a Compensation Committee. The members of the Audit Committee are Messrs. Edward Flood, Howard Balloch and Steven Rhodes. Mr. Rhodes replaced Mr. Shun-ichi Shimizu effective March 2, 2004. Mr. Flood, an independent director of the Company, has been determined by the Board of Directors to be an Audit Committee financial expert. The members of the Compensation Committee are Messrs. Edward Flood, Howard Balloch and Steven Rhodes. Mr. Rhodes was appointed to the Compensation Committee on March 2, 2004.

Management is responsible for our financial reporting process including our system of internal control over financial reporting and for the preparation of consolidated financial statements in accordance with generally accepted accounting principles in Canada. Our independent auditors are responsible for auditing those financial statements. The members of the audit committee are not our employees, and are not professional accountants or auditors. The audit committee's primary purpose is to assist the Board of Directors to fulfill its oversight responsibilities by reviewing the financial information provided to shareholders and others, the systems of internal controls which management has established to preserve our assets and the audit process. It is not the audit committee's duty or responsibility to conduct auditing or accounting reviews or procedures or to determine that our financial statements are complete and accurate and in accordance with generally accepted accounting principles in Canada. In giving its recommendation to the Board of Directors, the audit committee has relied on management's representations that the financial statements have been prepared with integrity and objectivity and in conformity with generally accepted accounting principles in Canada and on the opinion of the independent auditors included in their report on our financial statements.

Based solely on a review of the reports furnished to us, we believe that during 2003 all of our directors, executive officers and 10% shareholders complied with the applicable requirements for reporting initial ownership and changes in ownership of our common shares.

Code of Business Conduct and Ethics

We have a Code of Business Conduct and Ethics applicable to all employees, officers and directors regardless of their position in our organization, at all times and everywhere we do business. The Code provides that our employees, officers and directors will uphold our commitment to a culture of honesty, integrity and accountability and that we require the highest standards of professional and ethical conduct from our employees, officers and directors. Our Code of Business Conduct and Ethics has been filed as Exhibit 14.1 to this Annual Report.

ITEM 11. EXECUTIVE COMPENSATION

In accordance with the requirements of applicable securities legislation in Canada, the following executive compensation disclosure is provided in respect of the Company's President and Chief Executive Officer as at December 31, 2003, and each of the Company's four most highly compensated executive officers ("Named Executive Officers") whose annual compensation exceeded Cdn$100,000 in the year ended December 31, 2003. During the year ended December 31, 2003, the aggregate compensation paid to all executive officers of the Company whose annual compensation exceeded Cdn$40,000 was US$1,300,000.00.

Summary Compensation Table

The following table sets forth a summary of all compensation paid during the years ending December 31, 2001, 2002 and 2003 to each of the Named Executive Officers.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Annual Compensation			Long Term Compensation			All Other Compen-sation
					Awards		Payouts	
		Salary $US	Bonus $US	Other Annual Compen-sation	Securities Under Options/ SARs Granted (#)	Restricted Shares or Restricted Share Units	LTIP Payouts	
E. Leon Daniel	2003	332,610	81,123[9]	6,133[6]	-	-	-	9,792[7]
President & Chief Executive	2002	266,500		2,674[6]	-	-	-	5,415[7]
Officer[1]	2001	150,000		2,046[6]	-	-	-	-
Patrick Chua	2003	144,000	32,449[9]	5,262[6]				
Executive Vice President[2]	2002	182,970	-	5,083[6]	60,000	-	-	-
	2001	180,000	-	12,794[6]	-	-	-	-
John O'Keefe	2003	205,562		8,742[6]	-			24,898[8]
Executive Vice President Investor	2002	219,845	-	7,716[6]	75,000	-	-	7,200[7]
Relations & Chief Financial Officer[3]	2001	174,955	-	6,455[6]	250,000	-	-	5,250[7]
David R. Martin	2003	205,562	54,082[9]	3,057[6]				9,792[7]
Chairman[4]	2002	253,167	-	3,074[6]	-	-	-	7,200[7]
	2001	150,000	-	2,546[6]	-	-	-	3,000[7]
Gerald Moench	2003	150,000	33,801[9]	4,379[6]				
Executive Vice President[5]	2002	152,475	-	3,535[6]	50,000	-	-	
	2001	150,000	-	3,085[6]	-	-	-	

(1) Mr. Leon Daniel was appointed President and Chief Executive Officer on June 22, 1999, and has been a director of the Company since August 25, 1998.
(2) Mr. Chua was appointed as an Executive Vice President in June 1999.
(3) Mr. O'Keefe was Executive Vice President Investor Relations and Chief Financial Officer from September, 2000 to December 2003.
(4) Mr. Martin has been Chairman and one of the Company's directors since August 1998.
(5) Mr. Moench was appointed an Executive Vice President in June 1999.
(6) Includes premiums paid by us on behalf of the Named Executive Officer for medical, dental and other health insurance coverage.
(7) Company's matching contribution to the 401(k) plan, a US defined contribution retirement plan available to US employees.
(8) Includes Company's matching contribution to the 401(k) plan of $9,792 plus accrued vacation pay of $15,106.
(9) Bonuses earned in 2003 are payable in cash and Company shares from the Share Bonus Plan at fair market value on date of approval by the Compensation Committee.

Options and Stock Appreciation Rights (SARs)

No options were granted to our Named Executive Officers in the financial year ended December 31, 2003.

Aggregated Option Exercises in Last Fiscal Year and Year End Option Values

During the financial year ended December 31, 2003, John O'Keefe exercised options for 200,000 shares at Cdn. $6.22 per share, 100,000 shares at Cdn. $3.60 per share and 30,000 shares at Cdn. $3.10 per share and Gerry Moench exercised options for 50,000 shares at Cdn. $2.50 per share. No other named executive officers exercised options in 2003.

Name	Shares Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options at December 31, 2003 (#)	Value of Unexercised In-the-Money Options at December 31, 2003 ($)
E. Leon Daniel	—	—	666,667	725,001
Patrick Chua	—	—	560,000	1,361,000
John O'Keefe	330,000	805,229	50,000	62,500
Dave Martin	—	—	3,400,000	14,790,000
Gerald Moench	50,000	161,954	195,000	495,750

Indebtedness of Directors, Executive Officers and Senior Officers

There was no indebtedness of any officers, directors, employees and former officers, directors and employees of the Company in connection with the purchase of securities of the Company as at March 2, 2004.

Defined Benefit and Actuarial Plan

The Company does not presently provide a pension plan for our employees. However, in 2001 the Company adopted a defined contribution retirement or thrift plan (401(k) Plan) to assist U.S. employees in providing for retirement or other future financial needs. Employees' contributions (up to the maximum allowed by U.S. tax laws) are matched by the Company 50% starting in 2001 and increasing 10% per year thereafter to a maximum of 100%. The Company's matching contributions to the 401(k) Plan during 2003, 2002 and 2001 were $0.2 million for 2003 and $0.1 million per year for 2002 and 2001.

Employment Contracts, Termination of Employment and Change-In-Control Arrangements

The Company has written contracts of employment with Messrs. E. Leon Daniel and W. Gordon Lancaster. Until December 31, 2003, the Company also had a written contract of employment with Mr. John O'Keefe. Otherwise, the Company has no written employment contracts or termination of employment or change of control arrangements with any of our directors or Named Executive Officers. Each of the written employment contracts the Company has with the Named Executive Officers allows us to terminate the Named Executive Officer for cause in which case the Named Executive Officer would have no entitlement to any compensation with respect to the termination. None of the contracts provides for a change of control arrangement.

Mr. Daniel's contract provides for an annual salary of not less than $300,000 over the term of employment of five years, commencing on April 30, 2002, unless terminated earlier in accordance with the provisions of the contract. Either party may terminate the contract upon one year's notice provided however that the Company may terminate Mr. Daniel's employment at any time without notice by paying him an amount equal to the lesser of one year's salary or the prorated amount of his annual salary that he would have earned between the date of termination and the expiration of the contract term. Mr. Daniel is eligible to receive a cash bonus and a stock bonus each year, as determined by the Compensation Committee. Mr. Daniel is entitled to participate in the Company's employee benefit programs on the same basis as all of the Company's other employees.

Commencing in September 2000, the Company had an employment contract with Mr. John O'Keefe, the Company's former Executive Vice-President of Investor Relations and Chief Financial Officer. The contract had no fixed term of employment and provided for an annual salary of $200,000. Mr. O'Keefe was entitled to participate in the Company's employee benefit programs on the same basis as all of the Company's other employees. Effective December 31, 2003, Mr. O'Keefe elected to terminate his employment with the Company. Mr. O'Keefe received no additional compensation upon termination of his contract but was entitled to exercise his vested incentive stock options.

As of January 1, 2004, the Company entered into an employment contract with Mr. W. Gordon Lancaster having no fixed term of employment and providing for an initial annual salary of $200,000, subject to review annually by the Compensation Committee, and the same benefit entitlements available to the Company's other executive officers. Under the terms of the contract, Mr. Lancaster was granted an initial incentive stock option to acquire 250,000 common shares, which vest over 4 years and expire on the 5th anniversary of the date of grant. The Company may terminate Mr. Lancaster's employment for any reason by delivering to him six months' written notice.

Director Compensation

All independent directors receive director fees of $2,000 per month. We did not pay any other cash or fixed compensation to our directors for acting as such. We reimburse our directors for expenses they reasonably incur in the performance of their duties as directors and they are also eligible to participate in our Employees' and Directors' Equity Incentive Plan. One of our non-executive directors, John A. Carver, was engaged as a full time employee effective January 1, 2002 and receives a salary in his capacity as an employee.

Employees' and Directors' Equity Incentive Plan

Our Employees' and Directors' Equity Incentive Plan, as amended (the "Plan") consists of three component plans: a common share option plan (the "Share Option Plan"), a common share bonus plan (the "Share Bonus Plan"), and a common share purchase plan (the "Share Purchase Plan"). The purpose of the Plan is to advance our corporate interests by encouraging equity participation by our directors, officers, employees and service providers through the acquisition of our shares.

The following is a brief description of the terms of the Plan.

Share Option Plan

The Share Option Plan allows the Board of Directors to grant options to acquire our common shares in favor of our directors, officers, employees and service providers. Options are subject to adjustment in the event of a subdivision or consolidation of our common

shares, an amalgamation, or other corporate event affecting our common shares. Participation in the Share Option Plan is limited to directors, officers, employees and service providers, who are, in the opinion of our Board of Directors, in a position to contribute to our future growth and success.

In determining the number of common shares made subject to an option, we consider, among other things, the optionee's relative present and potential contribution to our success and to the prevailing policies of each stock exchange on which our shares are listed. The Board of Directors determines the date of grant, the number of optioned common shares, the exercise price per share, the vesting period and the exercise period. The minimum exercise price of any option granted under the Share Option Plan is the weighted average price of our common shares on the principal stock exchange on which our common shares trade for the five trading days prior to the date of grant.

Unless earlier terminated upon an optionee's death or termination of employment or appointment, options are exercisable for a period of up to ten years. We may, in our discretion, accelerate unvested options if a take-over bid is made for our common shares.

Share Bonus Plan

The Share Bonus Plan permits our Board of Directors to issue up to an aggregate maximum of 2,000,000 of our common shares as bonus awards to our directors, officers, employees and service providers on a discretionary basis having regard to such merit criteria as the Board of Directors may determine. As at December 31, 2003 there were 1,155,870 shares available to be issued from the Share Bonus Plan.

hare Purchase Plan

Participation in the Share Purchase Plan is limited to employees who have completed at least one year (or less, at the discretion of the Board of Directors) of continuous service on a full-time basis and who are designated by the Board of Directors as eligible to participate in the Share Purchase Plan.

Eligible employees may contribute up to 10% of their annual basic salary to the Share Purchase Plan in semi-monthly installments. We then make contributions on a quarterly basis equal to the employee's contribution.

At the end of each calendar quarter, the eligible employee receives a number of our common shares equal to the aggregate amount contributed by the employee participant and by us, on the participant's behalf, divided by the weighted average trading price of our common shares on our principal stock exchange during the previous three months.

The Share Purchase Plan component of the Plan has not yet been activated.

General

The aggregate maximum number of our common shares, which we may issue, or reserve for issuance under the Plan, is currently 20,000,000 common shares. Any increase is subject to Toronto Stock Exchange approval and approval by our shareholders. The maximum number of our common shares which we may, at any time, reserve for issuance to any one person under the Plan may not exceed 5% of our issued and outstanding common shares. As at December 31, 2003, there were 5,521,640 shares available to be issued from our Employees' and Directors' Equity Incentive Plan.

Our Board of Directors has the right to amend, modify or terminate our Equity Incentive Plan. However, any amendment to the Equity Incentive Plan which would materially increase the benefits under the Plan, materially modify the requirements as to eligibility for participation in the Plan or materially change the number of our common shares that may be issued or reserved for issuance under the Plan, is subject to Toronto Stock Exchange approval and the approval of our shareholders.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2003, our Compensation Committee consisted of Messrs. Edward Flood and Howard Balloch.

Board Compensation Committee Report on Executive Compensation

Our executive compensation program is administered by the Compensation Committee. The members of the Compensation Committee are both non-employee directors. Following review and approval by the Committee, decisions relating to executive compensation are reported to and approved by the full Board of Directors. The Committee has directed the preparation of this report and has approved its contents and its submission to shareholders.

The basic philosophy underlying our executive compensation program is that the interests of our executive officers should be aligned as closely as possible with the interests of Ivanhoe and its shareholders as a whole. Compensation for our executive officers is, accordingly, designed to achieve the following objectives: to provide a strong incentive to management to contribute to the achievement of our short-term and long-term corporate goals; to ensure that the interests of our executive officers and the interests of our shareholders are aligned; and to enable us to attract, retain and motivate executive officers of the highest caliber in light of the strong competition in our industry for qualified personnel. Our approach to compensation for senior executives and other employees is designed to recognize both corporate and individual performance, and the fact that, insofar as competition for highly skilled employees is intense, the levels of compensation we offer should be comparable to those offered elsewhere in our industry.

The compensation that we pay to our executive officers generally consists of cash, equity and equity incentives. Our compensation policy reflects a belief that an element of total compensation for our executive officers should be "at risk" in the form of stock options, so as to create a strong incentive to build shareholder value. The Compensation Committee oversees and sets the general guidelines and principles for the compensation packages for senior management. As well, the Compensation Committee assesses the individual performance of our executive officers and makes recommendations to the Board of Directors. Based on these recommendations, the Board of Directors makes decisions concerning the nature and scope of the compensation to be paid to our executive officers.

The base salaries of our executive officers are determined using a subjective assessment of each individual's performance, experience and other factors we believe to be relevant. We also consider recommendations from outside compensation consultants and use compensation data obtained from publicly available sources. We believe that current executive officer salaries are appropriate to ensure that our executive officers' compensation remains close to the median level of most of the comparative compensation data. All of our executive officers are eligible to receive discretionary bonuses, based upon Ivanhoe's overall performance and achievement of corporate objectives and our subjective assessment of each executive officer's contribution to such performance and achievement. Incentive bonuses awarded for the 2003 fiscal year consisted of 55% cash and 45% common shares issued at fair market value under the share bonus plan component of our Employees' and Directors' Equity Incentive Plan.

The specific relationship of corporate performance to executive compensation under our executive compensation program is created through equity compensation mechanisms. Incentive stock options, which vest and become exercisable through the passage of time, link the bulk of our equity-based executive compensation to shareholder return, measured by increases in the market price of our common shares. We also make discretionary bonus awards of common shares to our employees, including our executive officers. Such awards are intended to recognize extraordinary contributions to the achievement of corporate objectives.

Eligibility for participation from time to time in the various equity incentive mechanisms available under our Employees' and Directors' Equity Incentive Plan is determined after we have thoroughly reviewed and taken into consideration the individual performance and contribution to overall corporate performance by each prospective participant. All outstanding stock options that have been granted under our Employees' and Directors' Equity Incentive Plan were granted at prices not less than 100% of the fair market value of Ivanhoe common shares on the dates such options were granted.

Ivanhoe relies heavily upon stock options to compensate its executive officers. We believe that stock-based incentives encourage and reward effective management that results in long-term corporate financial success, as measured by stock appreciation. Stock-based incentives awarded to our executive officers are based on the Committee's subjective evaluation of each executive officer's ability to influence our long-term growth and to reward outstanding individual performance and contributions to our business. Our reliance upon stock options also reflects our stage of development, our limited history of earnings and the priority allocation of our limited financial resources to the development of our business.

The compensation paid to our Chief Executive Officer for the fiscal year ended December 31, 2003 was based on the same basic factors and criteria used to determine executive compensation generally. As with executive compensation generally, we believe that there is necessarily some subjectivity involved in determining the compensation of our Chief Executive Officer and we do not use predetermined performance criteria when setting his compensation. In determining an appropriate level of compensation for our Chief Executive Officer, we subjectively and quantitatively analyze his performance, Ivanhoe's overall corporate performance and our Chief Executive Officer's contribution to that performance. Specific factors considered in setting bonus levels include shareholder returns, our operational and financial results and the success of our acquisition, exploration and development programs and strategies. We also consider our Chief Executive Officer's level and scope of responsibility, experience and the compensation practices of other industry participants for executives of similar responsibility.

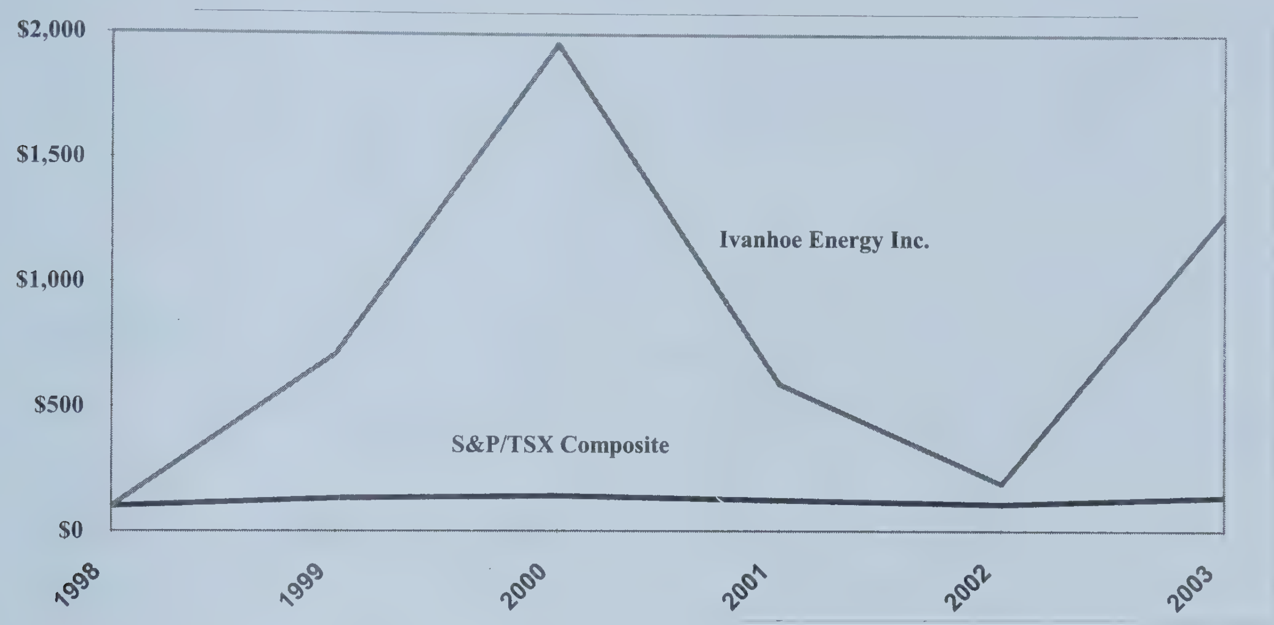
Our Chief Executive Officer's minimum salary is set by his employment contract, the material terms of which are described under "Employment Contracts, Termination of Employment and Change-in-Control Arrangements". This contract also provides that our Chief Executive Officer is eligible to receive, on an annual basis, a cash bonus and a non-cash bonus in an amount determined by the Committee based on such criteria as the Committee may determine from time to time. We awarded a bonus of $81,123 to our Chief Executive Officer in respect of the 2003 fiscal year. This bonus consisted of 55% cash and 45% common shares issued at fair market value under the share bonus plan component of our Employees' and Directors' Equity Incentive Plan. In determining the quantum of

our Chief Executive Officer's bonus, the principal factor we took into account was the creation of shareholder value, measured by the increase in the market price of our common shares during 2003. In this regard, reference is made to the performance graph that follows this report.

Submitted on behalf of the Compensation Committee:
Mr. R. Edward Flood
Mr. Howard R. Balloch

Performance Graph

The following graph and table compares the cumulative shareholder return on a $100 investment in common shares of the Company to a similar investment in companies comprising the S&P/TSX Composite Index, including dividend reinvestment, for the period from December 31, 1998 to December 31, 2003.



	As at December 31,					
	1998	1999	2000	2001	2002	2003
Ivanhoe Energy Inc.	Cdn. $100	Cdn. $711	Cdn. $1,961	Cdn. $592	Cdn. $189	Cdn. $1,276
S&P/TSX Composite Index	Cdn. $100	Cdn. $132	Cdn. $141	Cdn. $124	Cdn. $108	Cdn. $137

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Except as set forth below, no person or group is known to beneficially own 5% or more of our issued and outstanding common shares. Based on information known to us, the following table sets forth the beneficial ownership of each such person or group in our common shares as at February 2, 2004.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned(1)	Percentage of Class
Common Shares	Robert M. Friedland Flat B, 31st Floor Primrose Court 56A Conduit Road Hong Kong	46,611,725(2)	28.87%
Common Shares	Directors and Executive Officers as a Group (11 persons)	54,410,837(3)	33.49%

(1) Beneficial ownership is determined in accordance with the rules of the Securities and Exchange Commission and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of common shares of the person holding such

convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.

(2) 46,611,725 common shares are held indirectly through Newstar Securities SRL, Premier Mines Ltd. and Evershine LLC, companies controlled by Mr. Friedland.

(3) Includes 5,796,667 unissued common shares issuable to directors and senior officers upon exercise of incentive stock options.

Security Ownership of Management

The following table sets forth the beneficial ownership at February 2, 2004 of our common shares by each of our directors, our named executive officers and by all of our directors and executive officers as a group:

Title of Class	Name of Beneficial Owner	Amount and Nature of Beneficial Ownership (a)	Percentage of Class (b)	Incentive Stock Options Included in (a) (c)
Common Shares	David R. Martin	4,349,460	2.60	3,400,000
Common Shares	Robert M. Friedland	46,611,725	28.87	-
Common Shares	E. Leon Daniel	1,243,290	0.74	666,667
Common Shares	John A. Carver	543,547	0.33	250,000
Common Shares	R. Edward Flood	175,029	0.10	150,000
Common Shares	Shun-ichi Shimizu	98,500	0.06	-
Common Shares	J. Steven Rhodes	150,000	0.09	150,000
Common Shares	W. Gordon Lancaster	250,000	0.15	250,000
Common Shares	Patrick Chua	575,300	0.34	560,000
Common Shares	Gerald Moench	202,200	0.12	195,000
Common Shares	Howard R. Balloch	150,000	0.09	150,000
Common Shares	All directors and executive officers as a group (11 persons)	54,349,051	33.49	

Securities Authorized for Issuance under Equity Compensation Plans

Our shareholders have approved our Employees' and Directors' Equity Incentive Plan (the "Plan") and all amendments increasing the number of common shares available for issuance under the Plan. The Plan is intended to further align our directors' and management's interests with the company's long-term performance and the long-term interests of our shareholders. The material terms of the Plan are summarized in Item 11 Executive Compensation. The following information is as at December 31, 2003:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by shareholders	8,996,664	$2.64	5,521,640
Equity compensation plans not approved by shareholders	0	-	0
Total	8,996,664		5,521,640

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Transactions with Management and Others

The Company borrowed $1.25 million from Ivanhoe Capital Finance Ltd., a company wholly owned by Mr. Robert Friedland. The unsecured loan, due 90 days after written demand, or on the closing date of an equity financing or December 31, 2005 whichever occurs earliest, was repaid with accrued interest, at U.S. prime plus 3%, in September 2003. The Company negotiated a revolving credit facility of $1.25 million to re-establish or extend that loan in the future as needs arise.

Certain Business Relationships

We are parties to cost sharing agreements with other companies wholly or partially owned by Mr. Robert M. Friedland. Through these agreements, we share office space, furnishings, equipment and communications facilities in Vancouver and Singapore and an aircraft on a cost recovery basis. We also share the costs of employing administrative and non-executive management personnel at these offices. During the year ended December 31, 2003, our share of these costs was $0.9 million. The agreement for the usage of the aircraft was terminated in 2003.

During the year ended December 31, 2003 a company controlled by Mr. Shun-ichi Shimizu received $0.4 million for consulting services and out of pocket expenses.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table summarizes the aggregate fees billed by Deloitte & Touche LLP:

	Year ended December 31, ($000's)	
	2003	2002
Audit Fees (a)	$183	$148
Tax Fees (b)	43	95
Total	$226	$243

(a) Fees for audit services billed in 2003 and 2002 consisted of:
- Audit of the Company's annual financial statements
- Reviews of the Company's quarterly financial statements
- Comfort letters, statutory and regulatory audits, consents and other services related to Canadian and U.S. securities regulatory matters

(b) Fees for tax services billed in 2003 and 2002 consisted of tax compliance and tax planning and advice:
- Fees for tax compliance services totaled $36 thousand and $46 thousand in 2003 and 2002, respectively. Tax compliance services are services rendered based upon facts already in existence or transactions that have already occurred to document, compute, and obtain government approval for amounts to be included in tax filings and consisted of:
  i. Federal, state and local income tax return assistance
  ii. Preparation of expatriate tax returns
  iii. Assistance with tax return filings in certain foreign jurisdictions
- Fees for tax planning and advice services totaled $7 thousand and $49 thousand in 2003 and 2002, respectively. Tax planning and advice are services rendered with respect to proposed transactions or that alter a transaction to obtain a particular tax result. Such services consisted of:
  i. Tax advice related to structuring certain proposed mergers, acquisitions and disposals.

In considering the nature of the services provided by Deloitte & Touche LLP, the Audit Committee determined that such services are compatible with the provision of independent audit services. The Audit Committee discussed these services with Deloitte & Touche LLP and Ivanhoe management to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the U.S. Securities and Exchange Commission (the "SEC") to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Audit Committee Approval

Before Deloitte & Touche LLP is engaged by Ivanhoe or our subsidiaries to render audit or non-audit services, the engagement is approved by our Audit Committee. All services provided by Deloitte & Touche LLP after May 6, 2003 were approved by our Audit Committee.

The Audit Committee has adopted a pre-approval policy for audit or non-audit service engagements. This policy describes the permitted audit, audit-related, tax, and other services (collectively, the "Disclosure Categories") that Deloitte & Touche LLP may perform. The policy requires that, prior to the beginning of each fiscal year, a description of the services (the "Service List") expected to be performed by Deloitte & Touche LLP in each of the Disclosure Categories in the following fiscal year be presented to the Audit Committee for approval. Services provided by Deloitte & Touche LLP during the following year that are included in the Service List are pre-approved following the policies and procedures of the Audit Committee.

Any requests for audit, audit-related, tax, and other services not contemplated on the Service List must be submitted to the Audit Committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings. However, the authority to grant a specific pre-approval between meetings, as necessary, has been delegated to the Chairman of the Audit Committee. The Chairman must update the Audit Committee at the next regularly scheduled meeting of any services that were granted specific pre-approval.

In addition, although not required by the rules and regulations of the SEC, the Audit Committee generally requests a range of fees associated with each proposed service on the Service List and any services that were not originally included on the Service List. Providing a range of fees for a service incorporates appropriate oversight and control of the independent auditor relationship, while permitting us to receive immediate assistance from the independent auditor when time is of the essence. On a quarterly basis, the Audit Committee reviews the status of services and fees incurred year-to-date against the original Service List and the forecast of remaining services and fees for the fiscal year.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

The following financial statements and exhibits are filed as part of this Annual Report:

(a) 1. **Financial Statements:**

Deloitte & Touche LLP Auditors' Report on Consolidated Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2003 and 2002 and Consolidated Statements of Loss and Deficit and Consolidated Statements of Cash Flow of Ivanhoe Energy Inc. for the years ended December 31, 2003, 2002 and 2001.

Consolidated Balance Sheets of Ivanhoe Energy Inc. as at December 31, 2003 and 2002

Consolidated Statements of Loss and Deficit of Ivanhoe Energy Inc. For the years ended December 31, 2003, 2002 and 2001.

Consolidated Statements of Cash Flow of Ivanhoe Energy Inc. for the years ended December 31, 2003, 2002 and 2001.

2. **Financial Statement Schedules:**

Supplementary Disclosures about Oil and Gas Production Activities (Unaudited)

3. **Exhibits**

3.1 Articles of Ivanhoe Energy Inc. as amended to June 24, 1999 (incorporated by reference to Exhibits 1.1 through to 1.4 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)

3.2 Bylaws of Ivanhoe Energy Inc. (incorporated by reference to Exhibit 1.1 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)

10.1 Petroleum Contract for Kongnan Block, Dagang Oilfield of the People's Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999 (incorporated by reference to Exhibit 3.15 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)

Exhibits

10.2 Volume License Agreement dated April 26, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 3.37 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000)

10.3 Master License Agreement Amendment No. 1 dated October 11, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 10.18 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001)

10.4 Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Yudong block. (Incorporated by reference to Exhibit 10.21 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)

10.5 Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Zitongxi and Zitondong blocks. (Incorporated by reference to Exhibit 10.22 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)

10.6 Joint Venture Agreement and Operating Agreement dated 1 July 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc. on the Creslenn Ranch Area, Henderson County, Texas. (Incorporated by reference to Exhibit 10.23 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)

10.7 Joint Venture Agreement and Operating Agreement dated 1 October 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc., in the Bossier Trend, Anderson, Freestone & Henderson Counties, Texas (Incorporated by reference to Exhibit 10.24 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)

10.8	Modification Agreement for Petroleum Development Contract for Kongnan Block, Dagang Oilfield, the People's Republic of China, dated 24 October 2001. (Incorporated by reference to Exhibit 10.25 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.9	Consulting Agreement dated 13 January 2002 between Ivanhoe Energy Inc. and Nahwan Trading LLC. (Incorporated by reference to Exhibit 10.27 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.10	Petroleum Contract dated September 2002 for Zitong Block, Sichuan Basin of the People's Republic of China . (Incorporated by reference to Exhibit 10.12 of Form 10-K filed with the Securities and Exchange Commission on March 19, 2003)
10.11	Strategic Development Alliance Letter Agreement dated September 26, 2002 between the Company and CITIC Energy Ltd. (Incorporated by reference to Exhibit 10.13 of Form 10-K filed with the Securities and Exchange Commission on March 19, 2003)
10.12	Loan Agreement dated 31 December 2002 between the Company and Ivanhoe Capital Finance Limited. (Incorporated by reference to Exhibit 10.15 of Form 10-K filed with the Securities and Exchange Commission on March 19, 2003)
10.13	Amended Standstill Agreement between Linyi Holdings Limited and the Company dated May 5, 2003
10.14	Cooperation Agreement between Ensyn Petroleum International Ltd. and Ivanhoe Energy (USA) Inc. dated May 30, 2003
10.15	Employees' and Directors' Equity Incentive Plan – June 2003
10.16	Agreement in Principle for GTL Project Development between Syntroleum Corporation and the Company dated June 18, 2003

Exhibits

10.17	Amendment No. 3 to Master License Agreement between Syntroleum Corporation and the Company dated July 1, 2003
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23.2	Consent of Netherland, Sewell & Associates, Inc.
23.3	Consent of Deloitte & Touche LLP

31.1	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification by the Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

(b) **Reports on Form 8-K:**

The Company filed a report on Form 8-K on November 24, 2003, which included information under Item 5 of such form.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

IVANHOE ENERGY INC.

By: /s/ E. LEON DANIEL
Name: E. Leon Daniel
Title: President and Chief Executive Officer Dated: March 2, 2004

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ E. LEON DANIEL E. Leon Daniel	President, Chief Executive Officer and Director (Principal Executive Officer)	March 2, 2004
/s/ W. GORDON LANCASTER W. Gordon Lancaster	Chief Financial Officer (Principal Financial and Accounting Officer)	March 2, 2004
/s/ DAVID R. MARTIN David Martin	Chairman of the Board and Director	March 2, 2004
/s/ ROBERT M. FRIEDLAND Robert M. Friedland	Deputy Chairman and Director	March 2, 2004
/s/ JOHN A. CARVER John A. Carver	Director	March 2, 2004
/s/ R. EDWARD FLOOD R. Edward Flood	Director	March 2, 2004
/s/ SHUN-ICHI SHIMIZU Shun-ichi Shimizu	Director	March 2, 2004
/s/ HOWARD R. BALLOCH Howard Balloch	Director	March 2, 2004
/s/ J. STEVEN RHODES J. Steven Rhodes	Director	March 2, 2004

EXHIBIT 31.1

CERTIFICATION BY THE CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, E. Leon Daniel, certify that:

1. I have reviewed this quarterly report on Form 10-K of Ivanhoe Energy Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
    a.) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b.) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    c.) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:
    a.) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b.) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

* * *

Date: March 2, 2004

Chief Executive Officer

By: /s/ E. Leon Daniel

E. Leon Daniel

EXHIBIT 31.2

CERTIFICATION BY THE CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, W. Gordon Lancaster, certify that:

1. I have reviewed this quarterly report on Form 10-K of Ivanhoe Energy Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
    - a.) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    - b.) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    - c.) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:
    - a.) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    - b.) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

* * *

Date: March 2, 2004

Chief Financial Officer

By: /s/ W. Gordon Lancaster

W. Gordon Lancaster

EXHIBIT 32.1

CERTIFICATION BY THE
CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, E. Leon Daniel, Chief Executive Officer, of Ivanhoe Energy Inc. (the "Company"), hereby certify that:

(a) the Company's periodic report on Form 10-K for the year ended December 31, 2003 (the "Form 10-K"), fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and related interpretations; and

(b) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

* * *

Chief Executive Officer

By: /s/ E. Leon Daniel

E. Leon Daniel

March 2, 2004

EXHIBIT 32.2

CERTIFICATION BY THE
CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, W. Gordon Lancaster, Chief Financial Officer, of Ivanhoe Energy Inc. (the ”Company”), hereby certify that:

(a) the Company’s periodic report on Form 10-K for the year ended December 31, 2003 (the “Form 10-K”), fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended, and related interpretations; and

(b) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

* * *

Chief Financial Officer

By: /s/ W. Gordon Lancaster

W. Gordon Lancaster

Date: March 2, 2004

EXHIBIT INDEX

Exhibit No.	Description
3.1	Articles of Ivanhoe Energy Inc. as amended to June 24, 1999 (incorporated by reference to Exhibits 1.1 through to 1.4 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)
3.2	Bylaws of Ivanhoe Energy Inc. (incorporated by reference to Exhibit 1.1 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)
10.1	Petroleum Contract for Kongnan Block, Dagang Oilfield of the People's Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999 (incorporated by reference to Exhibit 3.15 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)
10.2	Volume License Agreement dated April 26, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 3.37 of Amendment No. 2 to Form 20-F filed with the Securities and Exchange Commission on July 24, 2000)
10.3	Master License Agreement Amendment No. 1 dated October 11, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (incorporated by reference to Exhibit 10.18 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001)
10.4	Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Yudong block. (Incorporated by reference to Exhibit 10.21 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.5	Joint Study Agreement between Petro China Company Limited and Sunwing Energy Ltd. dated 29 March 2001, for the purposes of entering into Production Sharing Contracts on the Zitongxi and Zitongdong blocks. (Incorporated by reference to Exhibit 10.22 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.6	Joint Venture Agreement and Operating Agreement dated 1 July 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc. on the Creslenn Ranch Area, Henderson County, Texas. (Incorporated by reference to Exhibit 10.23 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.7	Joint Venture Agreement and Operating Agreement dated 1 October 2001 between Union Oil Company of California and Ivanhoe Energy (USA) Inc., in the Bossier Trend, Anderson, Freestone & Henderson Counties, Texas. (Incorporated by reference to Exhibit 10.24 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.8	Modification Agreement for Petroleum Development Contract for Kongnan Block, Dagang Oilfield, the People's Republic of China, dated 24 October 2001. (Incorporated by reference to Exhibit 10.25 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.9	Consulting Agreement dated 13 January 2002 between Ivanhoe Energy Inc. and Nahwan Trading LLC. (Incorporated by reference to Exhibit 10.27 of Form 10-K filed with the Securities and Exchange Commission on March 14, 2002)
10.10	Petroleum Contract dated September 2002 for Zitong Block, Sichuan Basin of the People's Republic of China. (Incorporated by reference to Exhibit 10.12 of Form 10-K filed with the Securities and Exchange Commission on March 19, 2003)
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